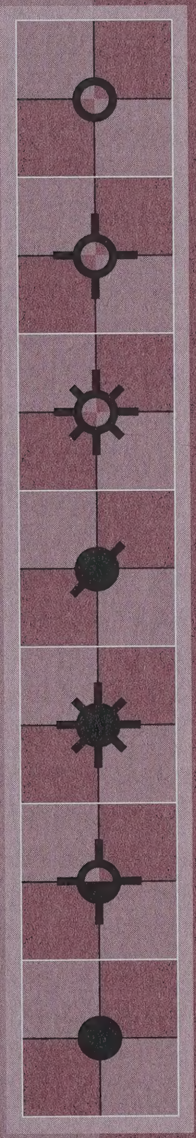
ENCOR INC.



1991 Annual Report

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ANNUAL GENERAL MEETING

The Annual General Meeting of shareholders will be held on Tuesday, May 5, 1992 at 10:00 o'clock in the forenoon (Calgary time) in the Glenbow Lecture Theatre, Calgary Convention Centre, 120 - 9th Avenue S.E., Calgary, Alberta.

CORPORATE PROFILE

Encor Inc., a Canadian public energy company, is active in the exploration, development and production of crude oil and natural gas in western Canada and selected international jurisdictions.

One of Encor's strengths as a senior producer in the Canadian oil and gas industry has been its extensive landholdings and associated technical database. A primary goal for the Company has been to strengthen the value of this asset base by increasing average working interests, level of operatorship and control of key production facilities. The completion of a one-time property swap or rationalization project with Amoco Canada Petroleum Company Ltd. ("Amoco") and Maligne Resources Limited ("Maligne") marked a major step forward in achieving this goal. With the closing of this transaction on March 1, 1992, Encor is better positioned to meet the challenges of the 1990's.

Encor has approximately 155 million common shares outstanding and preferred shares convertible into 75 million common shares. BCE Inc., one of Canada's largest public companies, is Encor's major common shareholder and holds all of Encor's preferred shares. Encor also has $100 million of 8.5 percent convertible subordinated debentures outstanding. The Company's common shares and debentures trade under the symbols "ECR" and "ECR.D" respectively on The Toronto Stock Exchange and the Montreal Exchange.

HIGHLIGHTS

FINANCIAL

(millions of dollars except per share amounts)	Year Ended December 31, 1991	1990
Revenues, net of royalties	**269.5**	313.6
Funds generated from operations	**66.1**	100.2
Per common share		
basic	**$ 0.43**	$ 0.66
fully diluted	**$ 0.28**	$ 0.44
Net loss applicable to common shareholders	**89.7**	71.3
Per common share	**$ 0.58**	$ 0.47
Capital expenditures and exploration expenses	**86.7**	112.3

	As at December 31, 1991	1990
Working capital	**10.6**	5.6
Total assets	**1,316.1**	1,396.9
Long-term debt	**544.0**	550.0
Shareholders' equity	**542.6**	616.4

OPERATIONS (1)

	Year Ended December 31, 1991	1990
Reserves – proved and probable (2)		
Oil and natural gas liquids (millions of barrels)	**176**	181
Natural gas (billions of cubic feet)	**1,239**	1,382
Landholdings (thousands of acres) (2)		
Canada		
Gross	**9,503**	19,190
Net	**2,609**	2,672
International		
Gross	**18,614**	19,263
Net	**3,090**	2,310
Production		
Oil and natural gas liquids (barrels per day)	**33,143**	34,519
Natural gas (millions of cubic feet per day)	**166**	182
Wells Drilled		
Canada		
Gross	**220**	332
Net	**16**	43
International		
Gross	**47**	92
Net	**3**	4

(1) *In this Annual Report the Company's oil and gas production, sales and reserves volumes are reported on the basis of its ownership interests before deducting burdens, royalties and foreign government takes.*

(2) *Year end reserve and land positions assume the rationalization project was effective December 31, 1991.*

LETTER TO SHAREHOLDERS

Nineteen ninety-one was an extremely tough year for the Canadian oil and gas industry. Overall, the demand for oil, gas and associated products remained near prior year levels despite the recession in North America. Unfortunately, product prices suffered across the board. Oil prices dropped significantly early in the year as a result of the commencement of the war in the Persian Gulf and saw further erosion from a rising Canadian dollar and widening quality differentials associated with heavy and sour crudes. Extreme competition among natural gas producers in the North American market place caused substantial reductions in gas prices. The large drop in gas price reflected the ongoing supply surplus and a move by many consumers towards purchasing gas on a short-term basis. As we enter the new year, Canadian producers continued to face mounting pressure to further reduce the price of natural gas, particularly for exports to California.

As a financially levered producer, Encor suffered considerably in this environment. Despite reducing capital expenditures, implementing staff reductions and placing restrictions on all other expenses within its control, the Company saw continued erosion in its funds generated from operations and an increase in its net loss position. In 1991, Encor's funds generated from operations dropped to $66 million from $100 million a year earlier, while the net loss applicable to common shareholders grew to approximately $90 million from $71 million. These results reflect a $44 million reduction in net revenues attributable to lower volumes and lower prices.

Oil and natural gas liquids production averaged 33,143 barrels per day in 1991 compared with 34,519 barrels per day in 1990, while prices for these products dropped by $4.47 per barrel to average $18.86 per barrel over the year. Natural gas volumes for the year dropped to 166 million cubic feet per day from 182 million cubic feet per day a year earlier. Over the same period, gas prices fell from $1.58 per thousand cubic feet to $1.35 per thousand cubic feet. The reduction in volumes largely reflects the impact of asset sales in 1990. Natural gas volumes declined further as nominations from a number of purchasers fell with the slowdown in the economy and intensified gas competition.

Encor's primary objective continues to centre on reducing long-term debt while retaining a strong nucleus of strategic assets. Falling product prices combined with an excess of assets available for sale have resulted in reduced property values. This has limited Encor's ability to successfully raise funds for debt repayment through asset sales. The change in price expectation has also eroded Encor's reserves position and underlying asset values. These changes contributed to our year end proved reserves reduction of approximately 197 billion cubic feet of natural gas and 4.1 million barrels of oil and natural gas liquids.

With the decline in revenues during the year, Encor adjusted its capital programs and cut discretionary expenditures and expenses. Funds were allocated to existing commitments and to projects which yielded high returns on investment and generated early cash flow. The majority of the Company's exploration activities were deferred unless funded through farm-out arrangements. In addition, the Company reduced the overall size of its organization by eliminating approximately one-third of the management positions and initiating general staff reductions which included the closure of its office in Sydney, Australia.

Despite the difficulties inherent in our working environment, Encor made significant progress in simplifying and streamlining its asset base. The Company successfully completed its major property rationalization project with Amoco Canada Petroleum Company Ltd. and Maligne Resources Limited. The transaction closed March 1, 1992 and is the largest one-time property swap in the history of the Canadian petroleum industry. As a result of the transaction, Encor will enjoy a 40 percent reduction in property count while realizing an increase in average working interest in remaining properties to 37 percent, up significantly from 15 percent pre-rationalization. The Company will also enhance its control over key facilities and increase operatorship of production from 13 percent to 47 percent.

OUTLOOK

While Encor has worked diligently over the past three years to reduce long-term debt and enhance shareholder value, the environment has been deteriorating and eroding the benefits of our actions. Despite solid progress in reducing debt, simplifying and restructuring our asset base and cutting costs, our residual debt position continues to constrain liquidity and limit the Company's ability to develop its asset base.

Under its bank loan agreement, the Company must comply with a number of covenants. These covenants were agreed at the Company's inception based on a number of factors including forecasts of cash flow and asset values. These forecasts depended on certain assumptions relating to future price levels and sales volumes which have changed substantially along with the economic environment. The substantial drop in prices in 1991, the lower than expected rates of take for gas and the reduced expectation for future price increases have not only significantly reduced revenues but have also eroded the underlying value of Encor's asset base. As a result, Encor is now in jeopardy of breaching two of these covenants in 1992. The potential breaches and consequences are discussed in more detail in the Management's Discussion and Financial Analysis.

In addressing these concerns, the Company, with the assistance of investment bankers, has considered a number of alternatives and will continue to give the matter top priority. The three most viable options appear to be restructuring of long term obligations, merger with another company, or a sale. Further information will be provided to shareholders as progress is made.

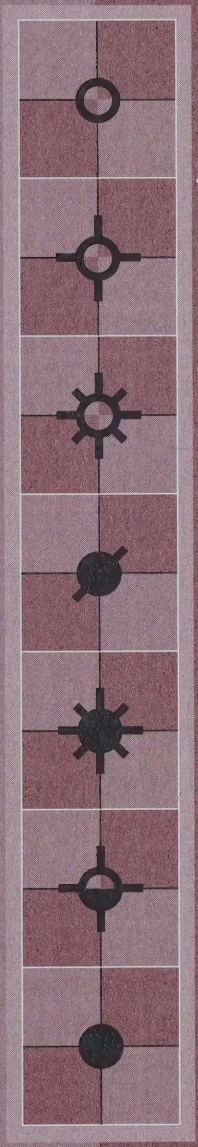
While the past year has been extremely difficult for Encor, management and staff have accepted the challenges and worked extremely hard to improve the Company's situation. Their dedication, commitment and skill have enabled Encor to successfully restructure its asset base in very difficult circumstances. These people have our respect and our thanks.

On behalf of the Board of Directors, we would like to welcome Bill Whelan and Joe Fridman who were elected to the Board at the last annual meeting. We would also like to thank Stuart Spalding for his contributions to Encor prior to resigning from the Board in May of 1991.

Gerald J. Maier
Chairman
March 16, 1992

Charles W. Fischer
President and Chief Executive Officer

OPERATIONS REVIEW



1991 ACCOMPLISHMENTS

Completed Rationalization

Strengthened and streamlined the Company's asset base through a major one-time property swap with Amoco and Maligne

Discoveries

Hanlan discovery well in West Central Alberta added proved and probable reserves of 24 billion cubic feet

Joint Venture

Enhanced drilling activities through joint venture program with Arkoma

Production

Produced 33,143 barrels per day of oil and natural gas liquids and 166 million cubic feet per day of natural gas

Development

Brought 30 million cubic feet per day of natural gas into production from existing discoveries.
Completed expansion of natural gas gathering system and plant facilities at Teepee Creek, Alberta

The Canadian oil and gas industry operated in a very difficult environment in 1991. Depressed natural gas prices, widening quality differentials for crude oil and a strong Canadian dollar eroded financial results throughout the industry. Amid this turbulent environment, Encor achieved varying degrees of success in meeting the primary operational goals that were stated in last year's Annual Report, as illustrated below:

To strengthen and streamline the Company's asset base by concluding a rationalization agreement with Amoco Canada Petroleum Company Ltd.

The rationalization purchase and sale agreement with Amoco and Maligne was concluded on January 31, 1992 with an effective date of March 1, 1992.

To annually increase the Company's gas reserves and production, after reflecting dispositions, through an exploration and development program in western Canada, at low finding and developing costs.

Encor was unable to meet this goal in 1991. Capital programs were reduced in response to the decline in revenues and cash flow during the year, and poor economics for gas. Funds were directed towards the development of existing discoveries which yielded high returns on investment and generated early cash flow. The majority of domestic exploration activities was deferred. Development activities added gas production of 30 million cubic feet per day during 1991.

To employ joint venture funding as a means of supplementing Encor's western Canada exploration and development programs.

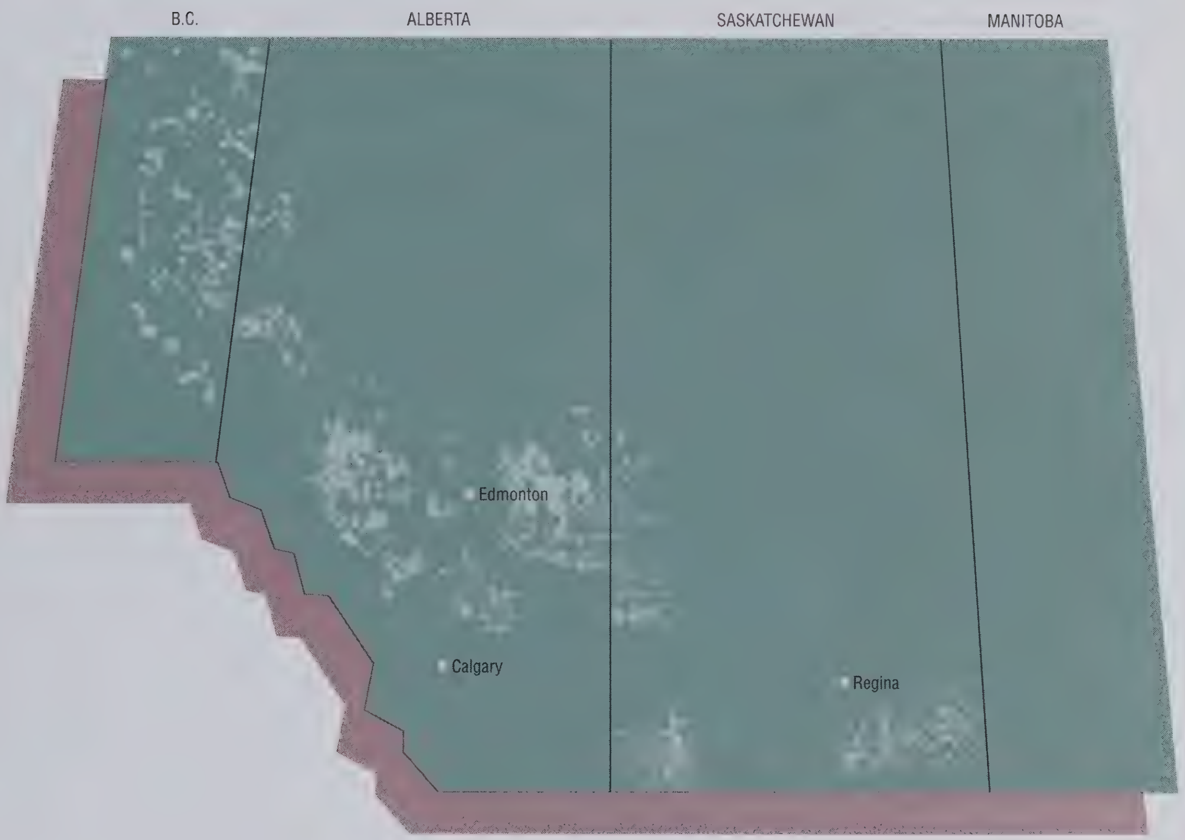
Encor signed a joint venture agreement with Arkoma Production Company of Canada ("Arkoma") primarily for development drilling activity in western Canada, commencing August 1, 1991.

RATIONALIZATION

Landholdings Before Rationalization

What is Rationalization? Rationalization is the name Encor gave to the one-time property swap between Amoco, Encor and Maligne. This three-way swap involved over $1 billion of interests in about 5,000 oil and natural gas properties in western Canada. All oil and natural gas assets within large defined geographical boundaries were traded such that the properties exchanged were, in total, of substantially the same net present value and cash flow.

Landholdings After Rationalization



One of the Company's primary goals since its inception three years ago has been to strengthen the value of its asset base by significantly reducing its property count while increasing working interests, level of operatorship and control over key production facilities. The completion of the rationalization project, which has been underway for over two years, is a major step forward in Encor's drive to achieve this goal.

Opportunities and Benefits of Rationalization

- *Increased operatorship of production from the previous 13 percent to approximately 47 percent;*
- *Increased average ownership interest in western Canada lands from 15 to 37 percent;*
- *Reduced western Canada property count by approximately 40 percent while maintaining overall value;*
- *Obtained control over key production facilities including the Edson and Sylvan Lake gas plants;*
- *Increased control over product marketing; and*
- *Concentrated 68 percent of undeveloped lands (excluding fee simple lands) in Encor's strategic exploration areas.*

Landholdings Encor's gross land position declined from 15.04 million acres to 6.77 million acres, while its net position increased slightly from 2.19 million acres to 2.47 million acres. The consolidation of landholdings provided by rationalization will allow Encor to focus its operational activities on an increased ownership stake in a reduced number of properties.

Reserves In preserving the net present value and cash flow of the properties exchanged, Encor reflected certain changes in its western Canada reserve profile. Total proved crude oil and natural gas reserves increased by 0.5 million barrels to 55.2 million barrels and by 28.4 billion cubic feet to 872.1 billion cubic feet, respectively. Total proved natural gas liquid reserves decreased by 4.7 million barrels to 18.1 million barrels.

Production The dramatic decrease in Encor's total properties combined with increased average ownership interest have streamlined Encor's sources of production. Encor produces approximately the same volumes on a barrel of oil equivalent basis from substantially fewer properties.

SUMMARY OF WESTERN CANADA RESERVES

Proved Reserves	Pre Rationalization [1]	Post Rationalization [2]
Oil (mmbbls)	54.7	55.2
Synthetic Oil (mmbbls)	20.3	20.3
Natural Gas Liquids (mmbbls)	22.8	18.1
Natural Gas (bcf)	843.7	872.1

(1) *Based on Coles Gilbert Associates Ltd. report as at December 31, 1991.*
(2) *Based on Coles Gilbert Associates Ltd. report assuming rationalization effective December 31, 1991.*

SUMMARY OF WESTERN CANADA LANDHOLDINGS
PRE AND POST RATIONALIZATION
(in thousands of acres)

(thousands of acres)	Pre Rationalization [1] Gross Acres	Pre Net Acres	Pre Average Ownership Interest	Post Rationalization [2][4][5] Gross Acres	Post Net Acres	Post Average Ownership Interest
Working Interest Undeveloped	5,890	1,112	19%	3,181	959	30%
Working Interest Developed	4,918	591	12%	2,284	612	27%
Fee Simple[3]	4,232	487	12%	1,306	902	69%
Total Landholdings	15,040	2,190	15%	6,771	2,473	37%

(1) *As at December 31, 1991.*
(2) *Based on Company land position assuming rationalization effective December 31, 1991.*
(3) *Represents an ownership interest in perpetuity in the subsurface mines and minerals. Some of the fee simple landholdings are leased and that portion in which the Company also has an interest is included in the Working Interest Developed category.*
(4) *In western Canada, the Company also has a royalty interest in 814,861 gross acres.*
(5) *The Company also holds frontier lands totalling 2,731,836 gross (135,717 net) acres.*

Major Activity Areas

Major Activity Areas Encor's Canadian activities continue to focus on specific areas in the western Canadian sedimentary basin. The rationalization project has enabled the Company to increase its working interests, level of operatorship and control over key production facilities in these areas. The result will be more streamlined operations where exploration, development and production are more closely integrated.

The Company's four strategic exploration areas are West Central Alberta, Grande Prairie, Fort Nelson and the British Columbia Foothills. Encor's average ownership interest in its undeveloped lands in these areas increased from 21 percent to 31 percent after rationalization. These areas include 68 percent of Encor's undeveloped land holdings excluding fee simple lands. Geographically, these strategic exploration areas represent less than 10 percent of the western Canadian sedimentary basin, but are estimated by the Energy Resources Conservation Board of Alberta to contain over 50 percent of the remaining potential for natural gas additions in western Canada.

MAJOR ACTIVITY AREAS

	Reserves[1] [2]			
	Oil and NGLs (mmbbls)	%	Average Natural Gas (bcf)	%
West Central Alberta				
Kaybob/Windfall	8.9	8.8	150.7	12.3
West Pembina/Brazeau River	8.6	8.5	140.3	11.5
Edson	1.9	1.9	185.3	15.1
Pembina Keystone	11.9	11.7	16.6	1.4
Sylvan Lake	6.2	6.1	38.0	3.1
Grande Prairie				
Progress/ Teepee Creek	5.3	5.2	78.2	6.4
Fort Nelson				
Hamburg	0.5	0.5	41.5	3.4
British Columbia Foothills	0.9	0.9	50.0	4.1
Other Development Areas				
Southeast Saskatchewan (Carlyle)	10.9	10.7	2.4	0.2
Southwest Saskatchewan (Shaunavon)	10.4	10.3	–	–
Clive/Drumheller	3.5	3.5	12.7	1.0
Other Conventional Canadian[3]	32.4	31.9	508.6	41.5
Total Western Canada	101.4	100.0	1,224.3	100.0

[1] *Based on Coles Gilbert Associates Ltd. report assuming rationalization occurred December 31, 1991.*
[2] *Includes proved and probable reserves for major properties within each key production and development area.*
[3] *Includes proved and probable reserves for minor properties within each key production and development area.*

Encor's reserves and production in western Canada are concentrated in nine key production and development areas which contain approximately 90 percent of the Company's reserves on a value basis. There is substantial overlap between these areas and the four strategic exploration areas. As a result, Encor is able to focus its capital and human resources in areas where high exploratory potential is complemented by existing operations and facilities.The following discussion reviews Encor's strategic exploration areas and the key production and development areas that fall within these regions.

WEST CENTRAL ALBERTA

The effect of rationalization on the Company's interest in West Central Alberta demonstrates the positive impact of the transaction. Encor's average ownership interest in undeveloped lands in this area has increased from 17 to 28 percent and now totals 938,678 gross (265,018 net) acres.

This strategic exploratory area has the potential for discoveries of both oil and deep gas reserves. Encor is well positioned to capitalize on exploration plays with its extensive land base and the support of five of the Company's key production and development areas.

Kaybob/Windfall Encor owns interests in a number of large mature gas fields and the network of pipelines and major gas processing plants that service the fields in this area. Over the past three years, Encor participated in several gas discoveries and drilled a number of gas development wells in the area. The focus now is to place these wells on production by connecting them to the existing gas processing infrastructure. In addition, capital programs are underway to maximize production from producing fields.

Although Kaybob/Windfall is predominantly a gas area, the Company has interests in two major oil pools, Kaybob South Triassic Units No. 1 and No. 2. Oil recovery in both pools is being enhanced under waterflood schemes. Recent optimization of the waterflood scheme in Unit No. 2 has resulted in a two-fold increase in production from the pool.

West Pembina/Brazeau River The West Pembina/Brazeau River area has long been an exciting and prosperous area for the oil industry. Encor's activities centre around its significant interests in the prolific West Pembina Nisku gas-condensate pools, the mature Brazeau River Elkton-Shunda gas pool and the recently developed Brazeau River Belly River oil pools.

A number of gas cycling schemes have been implemented in the West Pembina Nisku pools to maximize condensate recovery from these liquids rich gas reservoirs. Encor has interests in many of these pools as well as access to the two major gas plants that process the production. Capital programs initiated in 1988 to expand these gas plants and maximize production rates from the West Pembina Nisku pools were completed in 1991.

The Brazeau River Belly River oil field has been one of Encor's most active oil plays over the past several years. Successful step-out drilling continues to extend the field while waterflood schemes are being implemented in the existing producing areas to enhance production rates and ultimate oil recovery.

Three waterflood schemes are currently in various stages of development and several more are expected to be implemented over the next few years.

Edson As a result of rationalization, Edson is Encor's primary gas producing area accounting for 30 percent of the Company's natural gas production. Substantial excess deliverability exists and additional production can be achieved if market conditions improve.

The majority of Encor's natural gas production from this area is processed at the Edson gas plant which is now operated by Encor. Encor is taking an aggressive approach to attract additional outside gas to the Edson plant in order to utilize excess plant capacity. In addition, the Company has identified a number of exploration prospects in shallow horizons in the existing producing areas. If drilling proves successful, these pools can be quickly and economically placed on production through the gas processing infrastructure currently in place.

Pembina Keystone The majority of Encor's reserves and value in the Pembina Keystone area originates from 10 Belly River oil units where oil recovery is being enhanced by waterflood schemes. The most significant property is the Encor operated Pembina Belly River "C" East Unit where Encor has a 54 percent working interest. A waterflood scheme implemented in this unit in 1991 is expected to double oil production here over the next few years. In addition, a number of opportunities for optimizing other existing waterflood schemes have been identified by Encor for future implementation.

Sylvan Lake The Sylvan Lake area contains many sizeable oil pools and gas pools in several different geological horizons. As a result of rationalization, Encor's working interest in these pools has quadrupled and Encor is now the operator of several pools as well as the Sylvan Lake gas plant. The existing gas conservation scheme was expanded in 1991 to utilize the remaining excess gas plant capacity.

Encor's focus in the Sylvan Lake area is on oil development. The Company has identified significant potential to increase production and reserves through the initiation of new waterflood schemes, further step-out drilling and in-fill drilling.

GRANDE PRAIRIE

The strategic area of Grande Prairie, bordering northern Alberta and British Columbia, has been Encor's most active exploratory drilling area for the past four years. Discoveries such as the Progress "P" Pool which provided 2.6 million barrels of recoverable oil illustrates the type of potential in this area. Encor's average ownership interest in undeveloped lands in this area increased from 26 to 48 percent with the completion of rationalization. The Company now holds interests in 544,925 gross (259,612 net) acres. Future drilling opportunities will primarily follow-up previous discoveries particularly in the key production and development areas around Progress and Teepee Creek.

Progress The Progress area contains the Braeburn, Gordondale, Mirage, Pouce Coupe, Pouce Coupe South and Progress oil and gas fields. Encor has participated in the discovery of oil and gas reserves in over 10 different formations in this prolific, multi zone area. The installation of waterflood schemes in two Encor operated oil pools in 1990 and 1991 significantly increased the Company's oil reserves. Encor will continue to concentrate on waterflood opportunities in this area as well as the tie-in of shut-in gas reserves.

Teepee Creek The Teepee Creek area includes the Sexsmith gas field, the Teepee Creek gas field and the Teepee Creek gas plant, all of which are operated by Encor. The completion of a major expansion of the plant facility and associated Sexsmith gas gathering system in 1991 will more than double Encor's gas sales from this area in 1992. Future development will focus on keeping the area gas facilities fully utilized.

FORT NELSON

The Fort Nelson area continues to be strategic for the Company as it has potential for large gas reserves in thick Devonian reefs. As a result of rationalization, Encor's average ownership interest in undeveloped lands in this strategic exploratory area increased from 19 to 25 percent. The Company's interest now totals 387,902 gross (96,130 net) acres. Encor has three prospects ready to drill as funds become available through farmout. Fort Nelson includes the key production and development area of Hamburg where the Hamburg Slave Point gas pool was brought onstream in 1991.

NATURAL GAS RATIONALIZATION

Actual 1991 Operated and Non-Operated Production

Pro Forma 1991 Operated and Non-Operated Production Assuming Rationalization Effective January 1, 1991

By Major Property *Mmcfd, % of Total*	Pre Rationalization		Post Rationalization	
B.C.	14.8	9%	14.8	8%
Progress/Teepee Creek	6.4	4%	15.6	8%
Edson	13.5	8%	55.8	30%
Clive/Drumheller	2.3	1%	8.6	5%
West Pembina/Brazeau River	13.1	8%	13.1	7%
Kaybob/Windfall	35.6	21%	35.6	19%
Other	80.4	49%	42.2	23%

BRITISH COLUMBIA FOOTHILLS

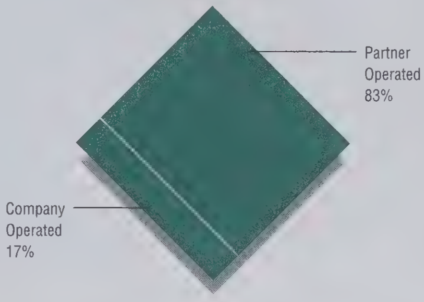
This gas prone region is one of Encor's most promising strategic areas. Previous discoveries by the industry have established large pools containing as much as 500 billion cubic feet of reserves. In 1991, Encor participated in the drilling of, and holds a 3.5 percent interest in, a discovery well at Murray River in the Grizzly Valley area. Testing indicated an initial capability of 40 million cubic feet of natural gas per day.

Encor currently holds 371,967 gross (88,687 net) acres of undeveloped lands in this region with an average ownership interest of 24 percent. The Company's acreage and ownership interests were not affected by rationalization. In addition to holding a minor interest in several of the established pools, Encor has land interests ranging up to 66.67 percent on three additional structures.

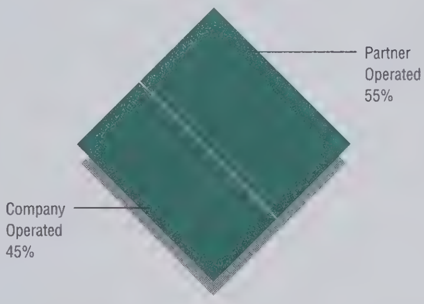
Encor has identified three prospects on its lands in this area which are ready to drill. One has been farmed out and is expected to be drilled in 1992 at no cost to the Company.

OIL AND NGLs RATIONALIZATION

Actual 1991 Operated and Non-Operated Production



Pro Forma 1991 Operated and Non-Operated Production Assuming Rationalization Effective January 1, 1991



By Major Property *Mbbls/d, % of Total*	Pre Rationalization		Post Rationalization	
Kaybob/Windfall	2.1	8%	2.1	8%
West Pembina/Brazeau River	2.0	7%	2.0	8%
Sylvan Lake/Pembina/ Keystone/Clive/Drumheller	1.8	7%	6.8	26%
Saskatchewan	4.1	15%	5.8	23%
Other	17.1	63%	9.1	35%

OTHER DEVELOPMENT AREAS

Saskatchewan Encor has been an active operator in Saskatchewan for a number of years and has district offices in southeastern Saskatchewan at Carlyle and southwestern Saskatchewan at Shaunavon. As a result of rationalization, Encor will become operator of several additional oil pools in each of these regions. Combining these new operations with Encor's existing operations is expected to result in substantially increased operating and overhead efficiencies.

Many of Encor's oil pools in southeastern Sask-atchewan are carbonate reservoirs with high oil recovery rates due to strong natural water drives. These types of reservoirs can be excellent candidates for the application of horizontal drilling technology. Encor has identified a number of potential horizontal drilling locations in these pools and is currently conducting a feasibility study.

The major Encor-operated oil pools in southwest Saskatchewan are subject to waterflood schemes. In addition, a tertiary recovery scheme to further enhance oil recovery has been installed in the Rapdan Unit. Encor's focus in this region is the further optimization of these oil recovery schemes.

1991 OVERVIEW

Drilling Activity During 1991, drilling activity was reduced in response to economic conditions in the industry and capital constraints within Encor. The Company participated in selected exploratory drilling for large gas accumulations. Development drilling activity centered around existing discoveries in order to maximize returns on investment and generate early cash flow. In total, Encor participated in the drilling of 220 exploratory and development wells in western Canada.

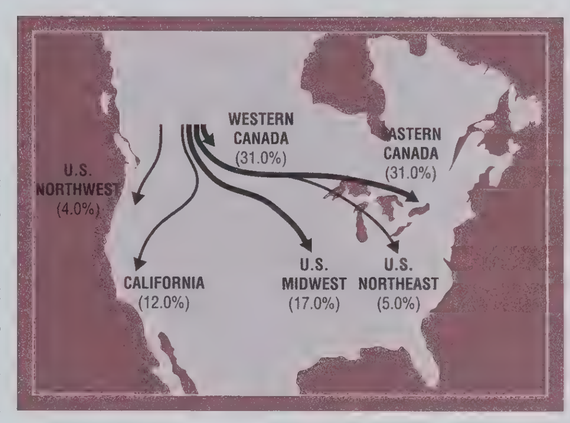
Encor restricted exploratory drilling expenditures to $3.2 million in 1991 as the majority of domestic exploration activities were deferred. The 6 (1.14 net) exploratory wells resulted in 3 (0.50 net) gas discoveries and 3 (0.64 net) dry holes. Encor's most notable discovery was the Hanlan well in west central Alberta. The well was drilled to a depth of 4,766 metres and flow tests indicated an initial capability of 11.2 million cubic feet of natural gas per day. This well is a two mile step-out well from the single well Hanlan-Swan Hills "B" Pool and the discovery indicates that the reserves may be significantly expanded in the area. Encor has an 11.8 percent working interest in this well and a 40.3 percent interest in offsetting lands.

Development expenditures totalled $42.3 million in 1991. Activities focused on development drilling, gas tie-in and plant facility projects. Development drilling resulted in 142 (6.31 net) oil wells, 57 (6.30 net) gas wells and 15 (2.01 net) dry holes for an overall success ratio of 93 percent. Tie-in projects at various locations added approximately 30 million cubic feet per day to Encor's natural gas deliverability. The most significant addition was the Hamburg Slave Point gas pool with 12 million cubic feet per day. Teepee Creek tie-ins and the tie-in of the Romeo well each accounted for five million cubic feet per day and the balance was from a number of other projects. Capital expenditures for these projects occurred late in the year and should enhance volumes in 1992.

The Progress/Teepee Creek area has been one of the Company's most active exploration and development areas over the past five years. In the Progress field, Encor installed a waterflood scheme in the Progress Halfway "P" pool in 1990 which will more than double oil recovery from the pool. A similar scheme was installed in the Progress "O" pool in 1991 and additional opportunities have been identified in the Progress "J" pool and the Mirage field. This area also includes the Gordondale property where the Company has developed substantial gas reserves in the prolific Doig "B" gas pool over the past year and plans are in place to continue these efforts in 1992.

Encor continued its activity in the Teepee Creek area in 1991 where it acquired a significant interest in the underutilized Teepee Creek gas plant in 1989. During the year, a major expansion of the plant facilities and the associated gas gathering system was completed. This project increased plant capacity to 28 million cubic feet per day from 17 million cubic feet per day, and expanded the natural gas liquids recovery facilities. Encor's share in the plant increased from 13.1 million cubic per day to 15.3 million cubic feet per day.

Joint Venture Agreement In August 1991, Encor commenced a development drilling joint venture with Arkoma. The joint venture provides Arkoma with the opportunity to participate in essentially all of the step-out development drilling activities undertaken by Encor in western Canada. In addition, Arkoma has an option to participate in Encor's explo-



ration drilling. The initial term of the joint venture is one year and may be extended for a second term. In general terms, under the agreement Arkoma will fund 70 to 100 percent of the costs of each well drilled depending on certain elections by Encor. Arkoma will earn 50 percent of Encor's interest subject to certain payout provisions or 100 percent subject to an overriding royalty. The intention is that Arkoma will incur expenditures of $10 million during the initial one year term. Encor is the manager and operator of the joint venture.

Encor's participation in the Arkoma joint venture will maintain its exposure to exploration and development drilling in 1991 and 1992, thus enabling the Company to continue exploiting the many opportunities on its extensive land holdings.

Marketing One of Encor's key operating goals has been to increase the level of production marketed by the Company. With the completion of rationalization, Encor will now be in a position to market directly a higher portion of its production.

Natural Gas In 1991, Encor increased the level of its natural gas production marketed internally from 36 to 45 percent and finalized negotiations on two new gas purchase contracts for maximum volumes totalling 36 billion cubic feet to be supplied over a 15 year period. In November, Encor commenced delivery under these contracts. The first contract is with Centra Gas British Columbia Inc., representing entry into the new Vancouver Island core market area, where Encor is supplying gas at a rate of 5 million cubic feet per day. As this market expands, Encor has the right to supply an additional 4.8 million cubic feet per day. The second contract is with Pacific Northern Gas Ltd., for 1.6 million cubic feet per day, to supply the core market in north central British Columbia.

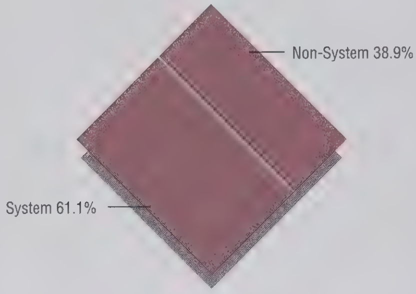
In 1991, the Company also reached agreement with Northland Power to supply approximately 20 million cubic feet per day to a power generation facility at Iroquois Falls, Ontario commencing November 1995 for 20 years. As of the time of writing, Ontario Hydro has indicated that they are reviewing their policy regarding non-utility generation. It is uncertain if this will result in the cancellation or deferral of this project. In addition, Encor signed a letter of intent for a gas supply contract with Indeck Energy Services of Hull, Inc. Beginning August 1994, Encor will supply up to 12 million cubic feet per day of natural gas for maximum volumes totalling 66 billion cubic feet over the life of the contract to a co-generation facility in Hull, Quebec. The negotiation of these contracts demonstrates the Company's continued strategy of moving towards longer term contracts with favourable pricing arrangements.

CANADIAN PRODUCTION VOLUMES MARKETED BY ENCOR

	Percent Marketed Directly			
	Estimate 1992	Actual 1991	Actual 1990	Pro Forma 1989
Natural Gas	75	45	36	20
Crude Oil	80	45	41	34
Natural Gas Liquids	40	31	24	24
Sulphur	60	60	60	14

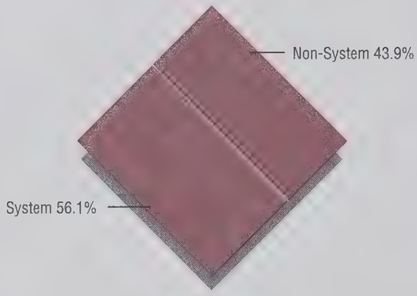
INDIRECT AND DIRECT GAS COMPARISON

1991 Actual



WGML	- 27.2%	Short Term	- 20.7%
Alberta & Southern	- 10.0%	Long Term	- 18.2%
Pan Alberta Gas	- 9.0%		
ProGas	- 4.3%		
Other System	- 10.6%		

1992 Estimated



WGML	- 33.2%	Short Term	- 28.5%
Alberta & Southern	- 7.2%	Long Term	- 15.4%
Pan Alberta Gas	- 7.1%		
ProGas	- 2.9%		
Other System	- 5.7%		

Encor continues to maintain a healthy diversity of buyers spread between system aggregators and non-system buyers. Encor's goal is to commit the majority of its reserves to long-term system and non-system contracts with periodic market responsive pricing. The Company also participates in short-term contracts with current market prices which offer high rates of take and require minimal reserve dedication.

Geographic diversity also continues to be strong. During 1991, the Company's three largest natural gas market areas were western Canada, eastern Canada and the U.S. Midwest. Sales to these areas accounted for 131 million cubic feet per day, representing approximately 79 percent of natural gas sales. Deliveries to California and the northwestern and northeastern U.S. accounted for the remaining 21 percent of 1991 sales. Encor's strategy of geographic diversity enables it to reduce its exposure to the volatility of certain markets, particularly California, where Canadian producers face mounting pressure to further reduce the export price of natural gas.

Crude Oil The majority of the Company's domestic crude oil production is sold under contracts to major refiners. Most contracts are automatically renewed unless either party gives notice of termination 30 days prior to expiry. In 1991, approximately 6,000 barrels per day were shipped on provincial gathering lines and delivered to major pipelines. As a result of rationalization, during 1992 this amount is expected to increase to 10,000 barrels per day providing increased marketing flexibility. The balance of the Company's crude oil is sold at the point of production. Customers purchase this crude on a posting or New York Mercantile Exchange pricing related basis using a combination of short and medium-term contracts.

All of the Company's Indonesian production is marketed by an independent trading company and is sold under short-term contracts.

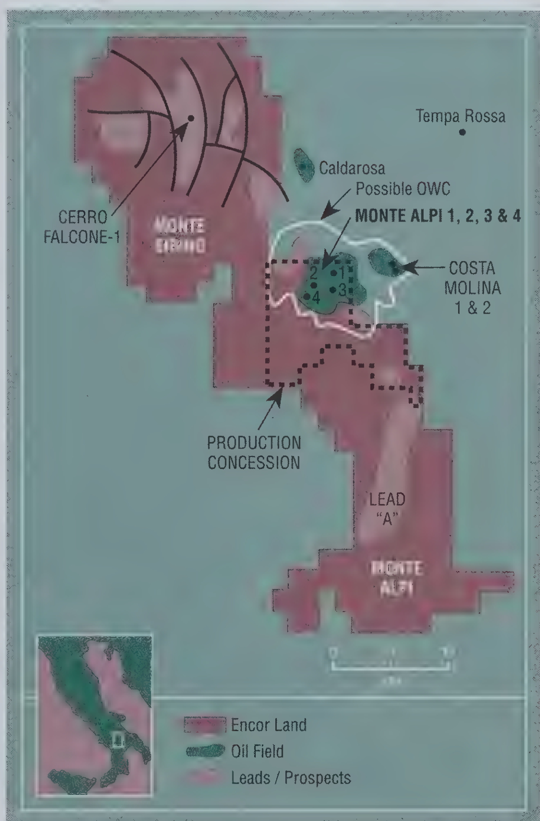
Natural Gas Liquids The Company's natural gas liquids are sold domestically under annual contracts to a variety of end users and marketers. Prices are based on monthly postings at Edmonton, Alberta, less adjustments for fractionation and transportation.

Sulphur Sulphur is sold offshore North America through Cansulex Ltd. and, beginning in 1992, through Prism Sulphur Corporation in which Encor is a shareholder. In North America it is sold to a number of end users and brokers under annual contracts at market prices.

INTERNATIONAL OPERATIONS

Introduction One of Encor's primary operational goals has been to add oil and natural gas liquids reserves through the Company's international exploration program over the medium term. Encor's strategy is to pursue international ventures in selected countries which offer excellent geological potential and favourable fiscal terms.

Encor has continued toward this goal in 1991 despite capital constraints. Progress was made by utilizing farmouts in certain jurisdictions; by disposing of non-strategic, minor interest properties; and by generally streamlining the Company's operations. In 1991, $25.1 million dollars or 29 percent of the Company's total capital expenditures and exploration expenses were allocated for international exploration and development programs. Activities were concentrated in Italy, Indonesia and Australia.



Italy Encor is very encouraged with the results that it has achieved in Italy. In 1989, the Company established the presence of hydrocarbons with the Monte Alpi No. 1 discovery. In March 1991, the Monte Alpi No. 2 appraisal well was completed and successfully tested at cumulative rates in excess of 3,500 barrels of oil per day. The well, which is located in the Southern Appennines in the province of Potenza, 360 kilometres southeast of Rome, was drilled to a total depth of 4,160 metres and encountered approximately 1,060 metres of gross hydrocarbon column and 700 metres of net oil pay in a carbonate sequence.

Encor has booked proven and probable reserves of 11.3 million barrels of oil and 15.1 billion cubic feet of natural gas based on the initial two wells at a net working interest of 20 percent. Significant potential exists in the area which will be further evaluated with wells Monte Alpi No. 3 and No. 4 in 1992.

Temporary facilities are currently being constructed to support an early production scheme. Production from Monte Alpi No. 1 and No. 2 wells is anticipated to commence in the fall at an expected gross rate of 2,500 to 3,000 barrels per day.

In January 1992, the Company signed a farmout agreement with Enterprise Oil Exploration Ltd. ("Enterprise"), currently a joint venture participant in Monte Alpi. Enterprise will pay for all expenditures incurred on Monte Alpi by the Company in 1992 to a maximum equal to the amount budgeted by the operator for the 1992 work program in consideration of a six percent interest thereby reducing the Company's interest to 14 percent. If the 1992 budget is not fully expended by the operator, Enterprise shall pay the difference directly to Encor. The farmout contains further options whereby, if certain events occur, a maximum of a further four percent interest may be farmed out in stages to Enterprise on similar terms.

INTERNATIONAL LANDHOLDINGS		
At December 31, 1991	Gross Acres	Net Acres
Algeria	3,329,845	1,831,415
Australia	4,087,280	491,840
Indonesia	10,310,225	584,445
Italy	424,835	57,068
New Zealand	462,176	124,961
Total	18,614,361	3,089,729

The Cerro Falcone No. 1 exploratory well in the Monte Sirino block, in which the Company holds a 20 percent working interest, was spudded in May 1991. Positive hydrocarbon indications were encountered over a gross interval of approximately 900 metres. An extensive testing program is underway and should be completed by the end of March 1992. Initial results have recovered 30 degree API oil and it is anticipated that final testing results will support an application for a production concession. The block is adjacent to the Monte Alpi block and the formation being tested is the same as that found in Monte Alpi.

Indonesia Since January 1991, all of Encor's international production has come from Indonesia. In 1991, production increased by 41 percent to 6,045 barrels of oil per day, up from 4,282 barrels per day in 1990. This increase is due to a full year of production from new fields, Intan and Widuri in the S.E. Sumatra Production Sharing Contract (PSC) and the Selatan field in the Malacca Strait PSC. The production is marketed by an independent trading company and is sold under short-term contracts. Despite infill drilling during 1991 and 1992, production from these fields is expected to decline by approximately 20 percent in 1992.

Exploration activity continues on both the S.E. Sumatra and Malacca Strait contract areas with 14 gross wells (0.64 net) drilled in 1991 and 19 gross wells (0.82 net) planned for 1992.

Encor's most significant exploratory property in Indonesia during 1991 was the Langsa block located in the Malacca Strait off the northeast corner of the island of Sumatra. The area is operated under a Joint Operating Agreement with Pertamina, the Indonesian state oil company. Each company originally held a 50 percent working interest. During 1991, Encor completed a farmout arrangement with Shell Exploration B.V. under which Shell will pay a major portion of the costs associated with Encor's commitment to spend U.S. $18.5 million during the first three years of the exploration phase. In return, Shell will earn 55 percent of Encor's interest in the joint venture.

A two-well exploratory drilling program was completed during the last half of 1991. Although both wells, Rajamuda No.1 and Tamiang No. 1, encountered minor hydrocarbon shows they were plugged and abandoned. Additional seismic is to be acquired in early 1992 with further drilling likely to occur later in the year.

Algeria In October 1991, Encor announced the signing of a production sharing contract with Enterprise Nationale Sonatrach, the Algerian state oil and gas company. The contract covers the 3.3 million acre Mehaiguene block which is located approximately 300 kilometres south of Algiers and immediately west of the giant Hassi R'Mel gas field.

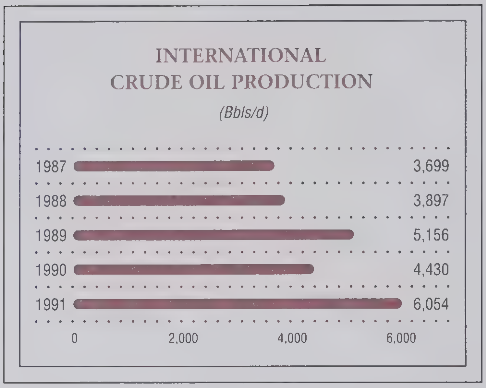
The initial three-year exploration phase includes the acquisition and processing of seismic and a three-well drilling program. Encor has entered into an agreement with Norcen International Ltd., whereby Norcen will pay 100 percent of the costs, to a maximum U.S. $6 million, of acquiring and processing the initial 1,700 kilometres of seismic over the subject block to earn a 45 percent interest in the production sharing contract. Encor will retain a 55 percent working interest and serve as operator. Initial drilling on the block is expected to commence during the last half of 1993. Activities in Algeria may be affected by current political uncertainties.

Australia In early 1991, Encor completed the first half of a six-well commitment in the AC/P13 permit area, located in the Timor Sea offshore north Australia. The three initial wells were dry and abandoned. Encor, as operator, has a 25 percent working interest in the permit.

A second three-well program commenced in November 1991. At year end, two wells had been drilled and both were dry and abandoned. The Company's interest in the first well had been farmed out to BHP Petroleum (Australia) Pty. Ltd. Encor participated fully in the second well. In February 1992, Encor participated fully in the third well which was also dry and abandoned.

ENCOR'S MAJOR ACTIVITIES IN 1992

Country	Block	Encor W.I.	Operator	1992 Proposed Activities
Indonesia	Langsa	22.5%	Pertamina/Encor	One exploratory well; seismic
Italy	Monte Alpi	14.0%	Petrex	One exploratory well One development well Construction of facilities Production start-up Monte Alpi 1 and 2
	Monte Sirino	20.0%	Petrex	Production testing – Monte Sirino
Algeria	Mehaiguene	55.0%	Encor	Seismic acquisition
Australia	AC/P13	25.0%	Encor	One offshore exploratory well



During the year, Encor farmed out a partial interest in the WA206P and WA207P permits located offshore on the Northwest Shelf. A well was drilled on each permit at no cost to Encor. Both wells were dry and abandoned. The Company retained working interests of 10 percent and 15 percent, respectively, in the areas. Subsequent to these transactions, the Company farmed out a further 10 percent in WA207P.

Plans for closing the Sydney office in early 1992 were initiated during the year and continuing activities will be monitored from Calgary.

New Zealand Activities throughout the year focused on continued technical studies and appraisal work on the three Company-operated licence areas.

The exploration term for PPL 38116, which contains the Kupe offshore gas-condensate field discovered in 1987, expired in February 1991. Applications for interim production mining licences were made for the Kupe and Toru discoveries. The Kupe licence was granted effective February 1992. Final approval of the Toru licence is still pending. Production mining licence approval allows the areas to be held for a period of four years and provides the time necessary for further evaluation in determining whether to proceed with field development. Marketing studies conducted during the year indicate reasonable potential for local markets in the 1995 timeframe.

Further activity in the offshore block PPL 38437, which contains the environmentally sensitive Sugar Loaf Islands marine protected area, is contingent upon government legislation expected early in 1992. Encor's interest in this licence is 22.5 percent.

Onshore PPL 38701 in which Encor holds a 30.5 percent working interest carries a commitment for one exploratory well in 1992. Technical evaluations in 1991 have identified a number of leads and prospects.

The Company initiated action in late 1991 on a possible disposition of its 40 percent working interest in the Kupe licence area. A final position is expected to be determined during the first quarter of 1992.

PRODUCTION AND RESERVES

Encor's crude oil and natural gas liquids production averaged 33,143 barrels per day for the year, down 1,376 barrels per day or four percent from 1990. Conventional oil and natural gas liquids production in Canada dropped by approximately 3,000 barrels per day year over year. Property dispositions which occurred late in 1990 represent 1,660 barrels per day of this reduction, while natural reservoir declines net of increases make up the balance. The total decrease was partially offset by a 1,624 barrel per day increase in international oil production.

Natural gas sales averaged 166 million cubic feet per day, a decrease of 16 million cubic feet per day compared to 1990. Asset dispositions late in 1990 account for 5 million cubic feet per day of the reduction and lower system gas sales caused by reduced rates of take from aggregators contributed to the remainder of the decline.

On a proved and probable basis, Encor's domestic conventional reserves at December 31, 1991 totalled 77.7 million barrels of oil, 23.8 million barrels of natural gas liquids and 1,224.3 billion cubic feet of natural gas. These reserves reflect the Company's position assuming rationalization was effective December 31, 1991. On a barrel of oil equivalent basis approximately 71 percent of Encor's domestic booked reserves are classified as proved. In addition, the Company has proved synthetic reserves of 20.3 million barrels.

During the year, Encor realized a downward revision in its proved reserves totalling 197.5 billion cubic feet of natural gas and 4.1 million barrels of oil and natural gas liquids. This decline represents 18 percent of proved natural gas reserves, and four percent of proved oil and natural gas liquids reserves reported as at December 31, 1990.

This reduction in reserves was due to a substantial reduction in the price forecast for natural gas which reflects deterioration in gas markets over the past year, lower than anticipated performance in a number of fields and a reassessment of the Company's shut-in natural gas reserves. In the event that gas markets and prices improve beyond current expectations, a portion of the reserve revisions which are price dependant may be added back to the proved category.

The reserve life indices of Encor's domestic proved and probable reserves based on actual 1991 production rates are 11 years, 13 years and 20 years for oil, natural gas liquids and natural gas, respectively.

Internationally, the Company reported 8.0 million barrels of proved oil reserves at December 31, 1991. The majority of the developed reserves of 5.4 million barrels are located in the S.E. Sumatra and Malacca Strait contract areas of Indonesia. Proved undeveloped and probable oil reserves of 2.6 and 10.3 million barrels, respectively, are principally related to the Company's interest in the Monte Alpi block in Italy. This block also contains proved and probable natural gas reserves of 3.0 and 12.1 billion cubic feet, respectively. Probable natural gas liquid reserves of 18.9 million barrels are attributable to the Kupe South field offshore New Zealand.

AVERAGE DAILY PRODUCTION

	1991	1990
Crude Oil (bbls)		
Canada		
Conventional	**20,019**	23,305
Synthetic	**2,064**	1,942
International	**6,054**	4,430
Natural Gas Liquids (bbls)	**5,006**	4,842
	33,143	34,519
Natural Gas (mmcf)	**166**	182

WESTERN CANADA RESERVE LIFE INDEX [1]

(Excluding Synthetic Reserves)

Years	**1991**	1990	1989
Oil	**11**	10	10
Natural Gas Liquids	**13**	18	15
Natural Gas	**20**	20	19

[1] *Year end proved and probable reserves divided by 1991 production.*

WESTERN CANADA RESERVES [1][2][3]

At December 31, 1991	Gross Reserves Oil (mmbbls)	NGLs (mmbbls)	Natural Gas (bcf)	Sulphur (mlt)
Western Canada Proved Reserves				
Developed	50.5	14.2	610.7	971
Undeveloped	4.7	3.9	261.4	406
Total Proved	55.2	18.1	872.1	1,377
Probable Reserves	22.5	5.7	352.2	783
Proved and Probable Reserves	77.7	23.8	1,224.3	2,160

(1) In addition, Encor has gross oil reserves in Syncrude Canada Ltd. of 20.3 million barrels of proved developed reserves and 16.7 million barrels of probable reserves.

(2) Gross reserves mean Encor's total working and royalty interest share of the recoverable reserves before the deduction of royalties payable to others.

(3) Based on Coles Gilbert Associates Ltd. report assuming rationalization was effective December 31, 1991.

INTERNATIONAL RESERVES [1][2]

At December 31, 1991	Gross Reserves Oil (mmbbls)	NGLs (mmbbls)	Natural Gas (bcf)
Proved Reserves			
Developed	5.4	–	–
Undeveloped	2.6	–	3.0
Total Proved	8.0	–	3.0
Probable Reserves	10.3	18.9	12.1
Proved and Probable Reserves	18.3	18.9	15.1

(1) Encor reserve estimates were prepared by in-house engineering staff. These reserves are located in Indonesia, New Zealand and Italy.

(2) Gross reserves means Encor's total working and royalty interest share of the recoverable reserves before the deduction of royalties payable to others and foreign government takes.

COMPANY PROVED RESERVES SUMMARY

(Excluding Synthetic Reserves)	Oil (mmbbls)	NGLs (mmbbls)	Natural Gas (bcf)
At December 31, 1990	76.8	26.7	1,095.2
Rationalization Adjustment	0.5	(4.7)	28.4
Revisions of Previous Estimates	(1.8)	(2.3)	(197.5)
Extensions and Discoveries	1.0	0.4	24.0
Production	(9.5)	(1.8)	(60.6)
Sales of Reserves in Place	(3.8)	(0.2)	(14.4)
At December 31, 1991	63.2	18.1	875.1

FINANCIAL REVIEW

1991 OVERVIEW

Funds Generated From Operations

Revenues net of cash expenses provided funds generated from operations of $66.1 million

Capital Program

Capital expenditures and exploration expenses amounted to $86.7 million

Long-Term Debt

Long-term debt reduced by a net amount of $6.0 million to $544.0 million

Forward Sale

Sold forward 1.5 million barrels of 1992 crude oil and condensate production at an average price of U.S. $21.92 per barrel

MANAGEMENT'S DISCUSSION AND FINANCIAL ANALYSIS

This discussion and analysis of financial condition and results of operations for each of the years ended December 31, 1991 and December 31, 1990, should be read in conjunction with the consolidated financial statements and related notes included in this annual report.

Overview

During 1991, Encor generated funds from operations of $66.1 million or 43 cents per common share (28 cents per common share on a fully diluted basis), down $34.1 million or 34 percent from 1990. The reduction is due primarily to a decline in revenues, net of royalties, partially offset by lower financial charges. Encor's net loss applicable to common shareholders increased from $71.3 million in 1990 to $89.7 million.

The following tables summarize revenues, expenses and funds generated from operations for each of the years ended December 31, 1991 and December 31, 1990.

SUMMARY CONSOLIDATED STATEMENTS OF INCOME
(millions of dollars)

Year Ended December 31	**1991**	1990
Revenues	**269.5**	313.6
Expenses	**283.5**	292.0
(Loss) income from operations	**(14.0)**	21.6
Other (income) expenses	**44.1**	78.2
Loss before taxes	**(58.1)**	(56.6)
Income and other taxes	**17.5**	1.4
Net loss	**(75.6)**	(58.0)
Provision for redemption premium on convertible preferred shares	**14.1**	13.3
Net loss applicable to common shareholders	**(89.7)**	(71.3)

SUMMARY CONSOLIDATED FUNDS GENERATED FROM OPERATIONS
(millions of dollars)

Year Ended December 31	**1991**	1990
Net loss	**(75.6)**	(58.0)
Expenses not requiring outlay of funds	**126.7**	137.1
Exploration expenses	**15.0**	21.1
Funds generated from operations	**66.1**	100.2

Results of Operations

Revenues

Revenues, net of royalties for 1991 were $269.5 million, a reduction of 14 percent compared to last year. Declines in both production volumes and product prices caused decreases of $31.9 million and $62.8 million respectively. These declines were partially offset by an increase in hedging revenue of $35.9 million and a reduction in royalties of $14.5 million. Hedging revenue represents income or losses from financial arrangements entered into by the Company to reduce the potentially adverse impact of fluctuations in crude oil prices.

The following tables analyze the Company's revenues for the years 1991 and 1990.

CANADIAN AND INTERNATIONAL REVENUES

(millions of dollars)

Year Ended December 31	1991			1990		
	Canada	International	Total	Canada	International	Total
Oil and natural gas liquids	**183.0**	**25.1**	**208.1**	255.4	23.8	279.2
Natural gas	**81.8**	–	**81.8**	104.9	–	104.9
Hedging	**20.4**	–	**20.4**	(15.5)	–	(15.5)
Other	**13.3**	–	**13.3**	13.6	–	13.6
Gross revenues	**298.5**	**25.1**	**323.6**	358.4	23.8	382.2
Less royalties	**54.1**	–	**54.1**	68.5	0.1	68.6
Net revenues	**244.4**	**25.1**	**269.5**	289.9	23.7	313.6

BARREL OF OIL EQUIVALENT ANALYSIS

($ per barrel of oil equivalent)[1]

Year Ended December 31	1991			1990		
	Canada	International[2]	Total	Canada	International[2]	Total
Gross revenues	**18.69**	**11.35**	**17.80**	20.26	14.73	19.79
Royalties	**3.39**	–	**2.98**	3.87	0.05	3.55
Net revenues	**15.30**	**11.35**	**14.82**	16.39	14.68	16.24

[1] Barrels of oil equivalent have been calculated by equating ten thousand cubic feet of natural gas to one barrel of oil, one barrel of pentanes to one barrel of oil, two barrels of liquid petroleum gases to one barrel of oil and 0.25 tons of sulphur to one barrel of oil.

[2] Barrel of oil equivalent analysis for Indonesian production is based on gross production volumes and the Company's revenues, net of the Indonesian government's take.

ANALYSIS OF GROSS REVENUE VARIANCES BETWEEN 1991 AND 1990[1]

(millions of dollars)

	Canada				International				
	Volume	Price	Other	Total	Volume	Price	Other	Total	Total
Oil and natural gas liquids	(26.7)	(45.7)	35.9[2]	(36.5)	4.2	(2.9)	–	1.3	(35.2)
Natural gas	(9.4)	(14.0)	0.3	(23.1)	–	–	–	–	(23.1)
Processing and other	–	(0.2)	(0.1)	(0.3)	–	–	–	–	(0.3)
	(36.1)	(59.9)	36.1	(59.9)	4.2	(2.9)	–	1.3	(58.6)

[1] Unfavourable variances denoted by ( )
[2] This variance relates to the hedging programs.

Total oil and natural gas liquids averaged 33,143 barrels per day for 1991, down 1,376 barrels per day or 4 percent from the same period in 1990. Conventional oil and natural gas liquids production in Canada dropped by approximately 3,000 barrels per day year over year. Property dispositions which occurred late in 1990 account for 1,660 barrels per day and natural reservoir declines, net of additions, make up the balance. This decrease was partially offset by a 1,624 barrel per day increase in international oil production.

Natural gas sales declined 16 million cubic feet per day from 182 million cubic feet per day during 1990 to 166 million cubic feet per day during 1991. Asset dispositions late in 1990 account for 5 million cubic feet per day of this reduction and lower system gas sales, caused by reduced rates of take from aggregators, contributed to the remainder of the decline.

The following table summarizes average daily sales volumes for 1991 and 1990.

AVERAGE DAILY SALES VOLUMES

	1991	1990	% Change
Oil and natural gas liquids (bbls/day) – Canada	**27,089**	30,089	(10)
– International	**6,054**	4,430	37
	33,143	34,519	(4)
Natural gas (mmcf/day)	**166**	182	(9)

The price of West Texas Intermediate crude oil ("WTI"), a bench mark for industry pricing, averaged U.S. $21.47 per barrel for 1991 compared to U.S. $24.22 per barrel for 1990. The average WTI price, particularly in 1990, was significantly influenced by the sharp increase in oil and liquids prices following the Iraq invasion of Kuwait in August 1990. The decrease in Encor's crude oil and natural gas liquids price from Cdn. $23.25 per barrel in 1990 to $18.50 in 1991 exceeded the decrease in the WTI crude oil price due to movements in quality differentials and exchange rates. Since Encor's blended crude oil production for the year was medium quality, approximately 32° API, the Company received $4.05 less than Edmonton refinery posted prices for premium 40° API crude, compared to $3.33 less in 1990. Compounding this decrease was an increase in the average value of the Canadian dollar from U.S. $0.8573 in 1990 to U.S. $0.8728 in 1991.

Natural gas prices for 1991 averaged $1.35 per thousand cubic feet, $0.23 per thousand cubic feet below the average price received during 1990, reflecting supply surpluses throughout North America.

The following table summarizes average prices for 1991 and 1990.

AVERAGE PRICES

	1991	1990	% Change
West Texas Intermediate (U.S. $/bbl)	**21.47**	24.22	(11)
Company sales prices – Oil and NGLs ($/bbl)	**18.86**	23.33	(19)
– Canada	**18.50**	23.25	(20)
– International	**21.97**	24.24	(9)
– Natural gas ($/mcf)	**1.35**	1.58	(15)

Expenses

Expenses declined by $8.5 million from $292.0 million for 1990 to $283.5 million for the current year. A reduction in exploration activity resulted in a decrease in exploration expenses of $6.1 million. Dry holes and abandonments were $4.6 million lower in 1991 than in 1990. The provision for depletion, depreciation and amortization in 1991 was $3.3 million lower than the provision recorded in 1990. An increase in the depletion and depreciation rate in the fourth quarter of 1991, following a downward revision to the Company's proved natural gas reserves, and an additional provision for future removal and site restoration costs of $5.0 million were more than offset by a decline in depletion, depreciation and amortization due to lower production volumes. The reduction in expenses for 1991 was partially offset by higher production and general and administrative expenses of $3.5 million and $3.1 million, respectively. The change in production expenses reflects higher workover and maintenance costs, gas processing fees and increased costs for processing synthetic crude. General and administrative expenses include approximately $2.0 million in severance costs due to staff reductions in the second quarter of 1991.

The following table summarizes expenses for both 1991 and 1990 on a barrel of oil equivalent basis.

BARREL OF OIL EQUIVALENT ANALYSIS

($ per barrel of oil equivalent)

	1991			1990		
	Canada	International	Total	Canada	International	Total
Production	**6.79**	**3.67**	**6.41**	6.00	4.24	5.86
Exploration	**0.44**	**3.57**	**0.82**	0.68	5.65	1.09
General and administrative [1]	**1.65**	**–**	**1.45**	1.31	–	1.20
Depletion, depreciation and amortization	**5.54**	**3.71**	**5.32**	5.27	4.15	5.18
Amortization of undeveloped rights	**1.10**	**–**	**0.96**	1.05	–	0.96
Dry holes and abandonments	**0.25**	**3.35**	**0.63**	0.19	7.84	0.83
Expenses	**15.77**	**14.30**	**15.59**	14.50	21.88	15.12

[1] *Corporate head office and general and administrative expenses are allocated to Canada.*

(Loss) Income From Operations

The table below summarizes (loss) income from operations on a barrel of oil equivalent basis.

BARREL OF OIL EQUIVALENT ANALYSIS

($ per barrel of oil equivalent)

	1991			1990		
	Canada	International	Total	Canada	International	Total
Net revenues	**15.30**	**11.35**	**14.82**	16.39	14.68	16.24
Expenses	**15.77**	**14.30**	**15.59**	14.50	21.88	15.12
(Loss) Income from operations	**(0.47)**	**(2.95)**	**(0.77)**	1.89	(7.20)	1.12

Other (Income) Expenses

Financial charges declined to $54.6 million in 1991 from $74.5 million in the prior year, with $7.9 million attributable to reductions in long-term debt and $9.3 million attributable to lower average interest rates. The reductions in long-term debt occurred primarily in the last quarter of 1990.

The sale of properties generated a pre-tax gain of $8.4 million in 1991 compared to a pre-tax loss of $6.8 million in 1990, an increase of $15.2 million.

Income and Other Taxes

Income and other taxes of $17.5 million were $16.1 million higher than 1990, despite the higher pre-tax loss in 1991. The $15.2 million increase in the pre-tax gain on property dispositions in 1991 resulted in a $13.8 million increase in deferred income taxes due to a significant portion of proceeds from 1990 property dispositions not being subject to tax. A reduction in profits eligible for the federal resource allowance in 1991, due to the decline in oil and natural gas revenues, also contributed to the increase in the income tax provision in 1991. Current income taxes, which arise from the Company's operations in Indonesia, increased by $2.4 million to $6.3 million in 1991 primarily as a result of higher revenues.

Liquidity and Capital Resources

Operating Activities

Funds from operations for 1991 were $66.1 million compared to $100.2 million for 1990. This 34 percent decrease is due mainly to lower revenues.

Investing Activities

The capital expenditures and exploration expenses, which represent the most significant application of cash, were curtailed during 1991 due to the decline in funds from operations.

Capital expenditures and exploration expenses for 1991 were $86.7 million, down 23 percent from 1990. Canadian spending totalled $52.8 million, down $21.1 million from 1990 levels with lower land acquisitions and exploration activities representing the majority of this reduction. Internationally, capital expenditures and exploration expenses declined from $33.8 million in 1990 to $25.1 million during 1991 reflecting farmouts and lower activity levels. Other expenditures in 1991 of $8.8 million were $4.2 million higher than in 1990 due to costs related to the rationalization project with Amoco and Maligne. This project, which was completed March 1, 1992, involved the exchange of jointly owned oil and gas properties in western Canada and resulted in each party owning a significantly higher interest in the properties retained after completion of the exchange.

The rationalization project with Amoco and Maligne was concluded on the basis of exchanging properties which, in total, were of similar net present value and cash flow. This has resulted in some changes in the Company's reserve profile and, as a result, the Company has more oil and natural gas and less natural gas liquids reserves than it held prior to rationalization. However, assuming that relative product prices do not change from projections at the time of completing the exchange, the change in the composition of production is not expected to have any significant impact on funds generated from operations in the future.

In 1991, Encor's investing activities replaced 12 percent of its oil and liquids production volumes and 40 percent of its natural gas production volumes. A review of Encor's proved conventional reserve volumes at December 31, 1991 resulted in a reduction of 197.5 billion cubic feet of natural gas and 4.1 million barrels of oil and natural gas liquids (18 percent and 4 percent respectively). Most of this reduction was due to a decline in the price forecast for natural gas, lower than anticipated performance in a number of fields and a reassessment of the Company's shut-in natural gas reserves. This reduction is not expected to impact funds generated from operations in 1992.

The reserve reduction did not result in a writedown, and related direct charge to income from operations, as the reserves, after revisions, continued to support the book value of the Company's oil and gas assets. However, income from operations for the fourth quarter of 1991 was reduced by approximately $3.1 million, and future income from operations will be reduced, due to the resulting 15 percent increase in the depletion and depreciation rate for Canadian oil and gas production.

CAPITAL EXPENDITURES AND EXPLORATION EXPENSES
(millions of dollars)

Year Ended December 31		**1991**	1990
Canada	– Land acquisitions	**0.2**	12.3
	– Exploratory drilling	**3.2**	5.5
	– Development drilling and production facilities	**40.7**	42.5
	– Syncrude	**1.6**	1.6
		45.7	61.9
International	– Exploratory drilling	**13.4**	16.7
	– Development drilling and production facilities	**3.8**	8.0
		17.2	24.7
Other		**8.9**	6.4
Incentives		**(0.1)**	(1.8)
		8.8	4.6
Total net capital expenditures		**71.7**	91.2
Exploration expenses	– Canada	**7.1**	12.0
	– International	**7.9**	9.1
		15.0	21.1
Total capital expenditures and exploration expenses			
	– Canada	**52.8**	73.9
	– International	**25.1**	33.8
	– Other	**8.8**	4.6
		86.7	112.3

Financing Activities

During the year ended December 31, 1991, the Company disposed of assets for an aggregate consideration of $45.0 million. The dispositions included the sale of gas processing facilities for a cash consideration of $25.0 million and a long-term note receivable of $8.0 million. The Company continues to process gas through these facilities on a processing fee basis. In addition, Encor exchanged all of its heavy oil interests at Lindbergh, Alberta and a portion of its interests in the Pembina Cardium Unit #9 in Alberta to eliminate the Dome Royalty. The Dome Royalty was

a charge of $0.05 per thousand cubic feet of natural gas and $0.50 per barrel of oil and natural gas liquids on all production from assets formerly held by TCPL Resources, one of Encor's subsidiaries. As a result of this transaction, Encor will lose approximately 1,140 barrels per day of oil production but will save approximately $7.9 million per year in royalty and other expenses.

During 1991, long-term debt was reduced by a net amount of $5.1 million with proceeds received from these sales of properties. A relative increase in value of the Canadian dollar resulted in an additional reduction in long-term debt of $0.9 million at year end as the Company's term bank loan is denominated in U.S. dollars. The Company's unused operating line of credit was $26.8 million at December 31, 1991. An additional $9.7 million related to the revolving portion of the production loan facility is also available.

Capitalization

Although long-term debt at December 31, 1991 of $544.0 million was $6.0 million lower than at December 31, 1990, the Company's debt to total capitalization ratio increased from 0.42:1 to 0.44:1. This change is due to a reduction of $73.8 million in shareholders' equity, caused primarily by the net loss incurred during the year.

Financial charges related to the Company's interest bearing debt decreased to $54.6 million in 1991 from $74.5 million in 1990. The Company's funds from operations before the deduction of financial charges were $120.7 million in 1991 and $174.7 million in 1990 and provided interest coverage of 2.2 times and 2.3 times in 1991 and 1990 respectively.

At December 31, 1991 the Company had working capital of $10.6 million compared to $5.6 million at the end of the prior year. Working capital at December 31, 1991 included cash and short-term deposits of $31.4 million.

Risks and Uncertainties

Hedging and Insurance Programs

As part of its overall risk management strategy, Encor from time to time implements hedging programs designed to limit exposure to crude oil price reductions and rising interest rates. The Company has entered into crude oil swap arrangements involving the sale of 1.5 million barrels of 1992 Canadian crude oil and condensate production at an average price of U.S. $21.92. In connection with certain of these arrangements, Encor has sold options which, if exercised, would result in an additional 0.8 million barrels being sold at U.S. $22.00.

The Company's term bank loan is in U.S. dollars. Since most of Encor's oil and natural gas liquids production and a significant portion of natural gas sales are indirectly priced in U.S. dollars, use of U.S. dollar denominated bank loans acts as a hedge against changes in foreign exchange rates.

At year end the average interest rate on the Company's long-term debt was 8.7 percent and 50 percent of the long-term debt was subject to fixed interest rates. In managing the exposure to increases in interest rates, the Company from time to time fixes the interest rate on a portion of its floating rate bank debt. Under interest rate swap agreements, interest on U.S. $90.0 million of the principal outstanding under the production loan facility at December 31, 1991 has been fixed at an effective interest rate of 9.7 percent per annum for periods ending between February 26 and November 1, 1992. Under interest rate cap agreements, interest on an aggregate amount of U.S. $40.0 million has been capped at an interest rate of 8.9 percent per annum. Interest on an additional U.S. $75.0 million has been capped at 8.9 percent for periods commencing between February 26 and November 2, 1992. The interest rate cap agreements expire between November 1, 1996 and November 2, 1997.

Encor also maintains a corporate insurance program to protect against losses due to accidental destruction of assets, well blowouts, pollution and other operating accidents or disruptions. In addition, operational guidelines, emergency response procedures, safety programs and environmental programs are in place to reduce potential loss exposure.

Sensitivities

Crude oil and natural gas prices, exchange rates and interest rates may change significantly due to circumstances which are beyond the control of the Company. The following table summarizes the Company's estimate of current sensitivity to changes in prices, exchange rates and interest rates for 1992, both prior to the hedging programs and after taking into account the hedging programs as they existed at December 31, 1991.

	Exposure Prior to Hedging		Exposure With Hedging in Place	
(millions of dollars)	Net Income	Funds Generated From Operations	Net Income	Funds Generated From Operations
U.S. $1.00/bbl WTI crude price	5.3	8.2	4.1	6.2
Cdn. $0.10/mcf natural gas price	3.4	5.5	3.4	5.5
U.S. $0.01 exchange rate	1.1	2.1	1.1	2.1
1% interest rate	2.2	3.7	2.0	3.4

Production Loan Facility

During 1992, the Company could breach certain of its covenants under its production loan facility (see "Outlook – Loan Agreement Covenants").

Other Risks and Uncertainties

The Company's capital expenditures, production, exploration and general and administrative expenses are subject to the effects of inflation. Prices received for oil and gas production are not readily adjustable to cover any inflation related increase in expenses.

The federal and provincial governments have historically had a significant influence on regulations and taxation pertaining to the oil and natural gas industry. The Company has no control over the extent of government intervention in the oil and gas industry or the level of taxation.

Outlook

Funds Generated from Operations

During 1991, the environment for natural gas markets seriously deteriorated as continued supply surpluses caused major declines in both natural gas prices and rates of take by purchasers. In addition, a stronger Canadian dollar and price differentials between light and heavy grades of crude oil, which increased significantly during the year, further reduced the netback price received by most Canadian producers. The Company has benefited from interest rate declines during 1991. However, these declines are not sufficient to offset the impact of lower commodity prices and the reduced sale volumes of natural gas. The outlook for improvement in oil and natural gas prices in 1992 and beyond is poor, with many independent forecasts anticipating little growth in commodity prices in the short to medium-term.

Based on assumptions that the price for WTI will trade in the U.S. $19.00 to $21.00 per barrel range throughout 1992 and further reductions in natural gas prices to $1.15 to $1.20 per thousand cubic feet, the Company anticipates that its funds generated from operations will decline to between $30.0 to $40.0 million in 1992. This represents a decrease of 40 to 55 percent from 1991. Funds generated from operations in years subsequent to 1992 are not expected to improve significantly because forecast product price growth will not offset the impact of normal production declines from oil and natural gas reservoirs.

Capital Program and Replacement of Reserves

Funds generated from operations are required to finance ongoing capital expenditures and exploration expenses and to provide the resources necessary to retire long-term obligations. Capital expenditures and exploration expenses totalled $86.7 million in 1991 and $112.3 million in 1990. The Company's capital and exploration program in 1992 will, to the extent possible, be limited to approximately $30.0 million.

The capital program in western Canada will be primarily directed towards the maintenance of production from existing proved oil and natural gas reserves and is not anticipated to replace a significant portion of reserves expected to be produced in 1992. The Company does not expect that its capital program can be materially increased in future years without a major increase in oil and natural gas prices or a significant injection of new capital. In the absence of such factors, the Company's oil and natural gas reserve base will continue to erode as produced reserves will not be replaced. Management estimates that an annual capital and exploration program of at least $130.0 million would be required to replace annual production.

Loan Agreement Covenants

As a result of the declines in revenues and funds generated from operations experienced by the Company during 1991, the reduced prospect for future increases in commodity prices and the related reductions to proved reserves reflected in the December 31, 1991 reserve evaluation, the Company could be in breach of two of the covenants in its production loan facility agreement (the "Facility") in 1992. The two covenants relate, respectively, to the maintenance of a consolidated net worth of $500.0 million and the maintenance of the value of certain assets (referred to as the borrowing base) in excess of loans outstanding under the Facility.

The consolidated shareholders' equity of the Company was $542.6 million as at December 31, 1991. If the Company's consolidated shareholders' equity declines to below $500.0 million, the lenders under the Facility (the "Lenders") may give notice of this breach which the Company must them remedy with 10 days. If the breach is not remedied, then an event of default will occur which would allow the Lenders, among other things, to demand immediate repayment of outstanding loan balances and appoint a receiver to manage the assets of the Company. In addition, the Company's other long-term borrowing arrangements contain cross-default provisions allowing, after expiry in certain cases of a grace period, for the accelerated repayment of debt if an event of default occurs under any long-term borrowing arrangement. This covenant could be breached as early as mid-1992.

The borrowing base is the lending value of the Company's western Canadian proved petroleum and natural gas reserves, determined using parameters established by the Lenders for this purpose and reviewed annually. As at December 31, 1991, the borrowing base exceeded the loans outstanding under the Facility based on the review completed by the Lenders in mid-1991.

As a result of the economic factors described above, the Company expects that the borrowing base review in mid-1992 will result in a significant borrowing base deficiency. The Lenders may then deliver a borrowing base shortfall notice which gives the Company 60 days to eliminate the deficiency. If the Company does not eliminate the deficiency it may deliver a borrowing base shortfall cure notice prior to the expiry of the 60-day period. This then extends the time to eliminate the deficiency to December 31, 1992. However, during this extended period, the Company would be required to dedicate essentially all net cash flow to repayment of loans outstanding under the Facility. Cash flow under the Facility is generally determined as net revenues less only operating and general and administrative expenses and certain minimum capital expenditures. If the deficiency is not eliminated by December 31, 1992, an event of default would occur.

Retirement of Debt and Redemption of Preferred Shares

The Company is currently required to make the following minimum repayments on its long-term debt commencing December 1994.

($ millions)	
1994	99.7
1995	105.4
1996	105.0
1997	73.9
1998	60.0
2000	100.0

In addition, the terms of the redeemable convertible preferred shares require the payment of quarterly dividends aggregating $20.1 million per annum commencing August 1994 and the mandatory redemption of the shares over a ten year period commencing in 2000. The redemption provision will require the payment of $29.8 million per annum. Based on current price forecasts, the Company anticipates that it will not generate sufficient funds from operations to meet these payments as they fall due.

Proposed Financial Restructuring

In order to avoid a breach of the covenants under its loan agreement and to address medium-term liquidity issues, the Company has reviewed a number of alternative sources of financing including debt and equity markets and the disposal of non-strategic properties.

The Company has concluded that it would be unable to raise additional capital through the debt and equity markets due to its current financial difficulties. With respect to asset dispositions, the proliferation of western Canadian oil and natural gas properties for sale together with declines in oil and natural gas prices has reduced market prices. As a result, interest savings realized by applying sales proceeds to reduce debt may be significantly less than the operating cash flow foregone. The Company continues its efforts to dispose of the majority of its international properties as they are mainly non-producing and a sale would not result in a material loss of cash flow. However, the Company has met with limited success due to market conditions.

As a result, the Company, with the assistance of investment bankers, is focusing its efforts on two main alternatives. Firstly, Encor is evaluating various means of restructuring its long-term obligations and, to this end, is holding ongoing discussions with certain of its lenders. At the same time, Encor continues to pursue a possible sale or merger of the Company. The outcome of these efforts is uncertain. The successful completion of a comprehensive financial restructuring, sale or merger may require the approval of the Company's preferred and common shareholders in addition to its lenders.

CONSOLIDATED FINANCIAL STATEMENTS

Management's Responsibility For Financial Statements

The accompanying consolidated financial statements of Encor Inc. and its subsidiaries are the responsibility of management and have been approved by the Board of Directors.

The financial statements have been prepared by management in conformity with Canadian generally accepted accounting principles. The financial statements include some amounts that are based on best estimates and judgements. Financial information used elsewhere in the annual report is consistent with that in the financial statements.

The management of the Company and its subsidiaries, in furtherance of the integrity and objectivity of data in the financial statements, has developed and maintains a system of internal accounting controls and supports a comprehensive program of internal audits. Management believes the internal accounting controls provide reasonable assurance that financial records are reliable and form a proper basis for preparation of financial statements and that assets are properly accounted for and safeguarded. The internal accounting control process includes management's communication to employees of policies which govern ethical business conduct.

The Board of Directors carries out its responsibility for the financial statements in this annual report principally through its audit committee, consisting solely of outside directors. The audit committee reviews the Company's annual consolidated financial statements and recommends their approval to the Board of Directors. The shareholders' auditors have full access to the audit committee, with and without management being present.

These financial statements have been examined by the shareholders' auditors, Peat Marwick Thorne, Chartered Accountants, and their report is presented herein.

S.J. Letwin

Stephen J. Letwin
Vice-President, Finance and Chief Financial Officer
February 24, 1992

Auditors' Report

To the Shareholders, Encor Inc.

We have audited the consolidated statements of financial position of Encor Inc. as at December 31, 1991 and 1990 and the consolidated statements of income, deficit and changes in financial position for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 1991 and 1990 and the results of its operations and the changes in its financial position for the years then ended in accordance with generally accepted accounting principles.

Peat Marwick Thorne

Chartered Accountants
Calgary, Canada, February 24, 1992

Consolidated Statements Of Financial Position

December 31
(millions of dollars)

ASSETS	1991	1990
Current Assets		
Cash and short-term deposits	$ 31.4	$ 5.8
Accounts receivable and prepaid expenses	45.3	73.8
Inventories	8.1	8.4
Total Current Assets	84.8	88.0
Property, Plant and Equipment (Note 3)	1,203.5	1,289.0
Other Assets and Deferred Charges	27.8	19.9
	$ 1,316.1	$ 1,396.9

LIABILITIES AND SHAREHOLDERS' EQUITY	1991	1990
Current Liabilities		
Short-term borrowings	$ –	$ 8.0
Accounts payable and accrued liabilities	73.0	68.7
Income and other taxes payable	1.1	1.5
Current portion of deferred revenue and other (Note 5)	0.1	4.2
Total Current Liabilities	74.2	82.4
Long-term Debt (Note 4)	544.0	550.0
Deferred Revenue and Other (Note 5)	24.0	27.6
Deferred Income Taxes	131.3	120.5
Shareholders' Equity		
Redeemable convertible preferred shares (Note 6)	262.4	248.3
Common shares (Note 6)	479.7	477.9
Deficit	(199.5)	(109.8)
Total Shareholders' Equity	542.6	616.4
Commitments and Contingencies (Notes 1 and 11)		
	$ 1,316.1	$ 1,396.9

On behalf of the Board:

S. G. Macri, Director   C.W. Finch, Director

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements Of Income

Year Ended December 31
(millions of dollars, except per share amounts)

	1991	1990
Revenues	**$ 269.5**	$ 313.6
Expenses		
Production	**116.6**	113.1
Exploration	**15.0**	21.1
General and administrative	**26.3**	23.2
Depletion, depreciation and amortization	**96.7**	100.0
Amortization of undeveloped rights	**17.5**	18.6
Dry holes and abandonments	**11.4**	16.0
	283.5	292.0
(Loss) Income from Operations	**(14.0)**	21.6
Other (Income) Expenses		
Financial charges (Note 7)	**54.6**	74.5
(Gain) loss on sale of properties (Note 3)	**(8.4)**	6.8
Interest and other income	**(2.1)**	(3.1)
	44.1	78.2
Loss before Taxes	**(58.1)**	(56.6)
Income and Other Taxes (Note 8)	**17.5**	1.4
Net Loss	**(75.6)**	(58.0)
Provision for Redemption Premium on Convertible Preferred Shares (Note 6)	**14.1**	13.3
Net Loss Applicable to Common Shareholders	**$ (89.7)**	$ (71.3)
Loss per Common Share	**$ (0.58)**	$ (0.47)

Consolidated Statements Of Deficit

Year Ended December 31
(millions of dollars)

	1991	1990
Deficit at Beginning of Year	**$ 109.8**	$ 38.5
Net Loss	**75.6**	58.0
Provision for Redemption Premium on Convertible Preferred Shares (Note 6)	**14.1**	13.3
Deficit at End of Year	**$ 199.5**	$ 109.8

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements Of Changes In Financial Position

Year Ended December 31
(millions of dollars, except per share amounts)

	1991	1990
Operating Activities (Note 9)		
Funds generated from operations	**$ 66.1**	$ 100.2
Decrease (increase) in non-cash working capital	**32.7**	(5.0)
	98.8	95.2
Investing Activities		
Expenditures on property, plant and equipment	**71.7**	91.2
Exploration expenses	**15.0**	21.1
Other assets and deferred charges	**8.2**	(4.0)
	94.9	108.3
Financing and Other Activities		
Proceeds from sale of properties	**45.0**	48.5
Repayment of long-term debt	**(5.1)**	(133.6)
Deferred revenue and other	**(12.4)**	(18.0)
Issue of common shares	**2.2**	6.6
Issue of long-term debt	**–**	100.0
	29.7	3.5
Cash and Short-term Deposits, net of Short-term Borrowings		
Increase (decrease)	**33.6**	(9.6)
Beginning of year	**(2.2)**	7.4
End of year	**$ 31.4**	$ (2.2)
Funds Generated from Operations per Common Share		
Basic	**$ 0.43**	$ 0.66
Fully Diluted	**$ 0.28**	$ 0.44

The accompanying notes are an integral part of these consolidated financial statements.

Notes To Consolidated Financial Statements

1. FUTURE OPERATIONS

During 1991 the environment for natural gas markets seriously deteriorated as continued supply surpluses caused major declines in both gas prices and rates of take by purchasers. In addition, a stronger Canadian dollar and price differentials between light and heavy grades of crude oil, which increased significantly during the year, further reduced the netback price for crude received by most Canadian producers. The outlook for improvement in oil and natural gas prices is poor, with many independent forecasts anticipating little growth in commodity prices in the short to medium-term.

The production loan facility (referred to in Note 4) of Encor Inc. and its subsidiaries ("the Company") includes a number of covenants certain of which the Company expects, if current events continue, to be in breach of as early as mid-1992. If an event of default occurs, the lenders may, among other things, demand immediate repayment of outstanding loan balances. The Company's other long-term borrowing arrangements contain cross-default provisions allowing, after expiry in certain cases of a grace period, for the accelerated repayment of long-term debt if an event of default occurs under any of the Company's long-term borrowing arrangements.

The Company is holding ongoing discussions with certain of its lenders with respect to a restructuring of its long-term obligations. The outcome of these discussions is uncertain and therefore the final form of a potential restructuring is not known. A comprehensive financial restructuring may require the approval of the Company's preferred and common shareholders in addition to its lenders.

These financial statements have been prepared on a going concern basis and, accordingly, do not include any adjustments to the amounts and classification of assets and liabilities that might be necessary should the Company be unable to achieve a restructuring of its long-term obligations.

2. ACCOUNTING POLICIES

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles.

Principles of Consolidation

The consolidated financial statements include the accounts of Encor Inc. and its subsidiaries, each of which is wholly owned.

The Company conducts substantially all of its exploration and production activities jointly with others and accordingly these consolidated financial statements reflect only the Company's proportionate interest in such activities.

Inventories

Material and supplies are recorded at the lower of average cost and net realizable value.

Property, Plant and Equipment

The Company follows the successful efforts method of accounting for exploration and development activities. Under this method, acquisition costs of oil and gas rights are capitalized. Exploratory drilling costs are capitalized and the costs of wells subsequently determined to be unsuccessful are charged to income. The costs of all offshore exploratory wells are written off immediately unless reserves are found which are expected to be developed for commercial production within a reasonable period of time. Other exploration expenses, including geological and geophysical costs, are charged to income as incurred. All development costs are capitalized.

Renewals or replacements which improve or extend the life of existing properties are capitalized. Those of a routine nature, as well as maintenance and repairs, are charged to income.

Depletion and depreciation of oil and gas properties are provided on the unit of production basis. Natural gas production and reserves, before deduction of royalties, are converted to equivalent units of crude oil based on the relative energy content of each commodity. Acquisition costs of proved reserves are depleted and depreciated over remaining proved reserves and other capitalized oil and gas costs are depleted and depreciated over remaining proved developed reserves. A valuation allowance for undeveloped rights is provided through amortization of costs; the amortization rate reflects the estimate of impairment of undeveloped rights. The Company employs the unit of production method for depleting and depreciating its developed oil sands properties. Costs relating to other assets are depreciated on the straight line method based on their estimated useful lives.

On disposal of an entire property unit, the asset cost and related accumulated depletion and depreciation are eliminated with any gain or loss reflected in income.

Future Removal and Site Restoration Costs

Estimated future removal and site restoration costs, net of salvage values, are provided for using the unit of production method and remaining proved reserves. Costs are estimated by the Company's engineers based on current regulations, costs, technology and industry standards. The annual charge is included in the provision for depletion, depreciation and amortization and the related accumulated provision is included in deferred revenue and other. Removal and site restoration expenditures are charged to the accumulated provision account as incurred.

Investment Tax Credits and Incentives

Investment tax credits and incentives are recorded as reductions of capital expenditures. Incentives are recorded in the year the qualifying expenditures are made. Investment tax credits are not recorded until there is reasonable assurance that they will be received.

Interest

Interest charges are expensed as incurred except for interest charges related to significant acquisitions of unproven property or major development projects which are capitalized as property, plant and equipment.

Deferred Natural Gas Revenue

Payments received pursuant to gas sales contracts for undelivered gas are deferred and recognized as revenue when deliveries are made. Deliveries under these contracts are to be made over a ten year period ending in 1994.

Hedging

The Company periodically enters into contracts to hedge its exposure to price fluctuations on a portion of its crude oil and condensate production. Gains or losses on these contracts are deferred and reported as adjustments to revenue in the related production month.

Translation of Foreign Currency

Monetary assets and liabilities are translated at the rates of exchange prevailing at the consolidated statement of financial position date. Non-monetary assets are translated at rates in effect at the dates the assets were acquired. Revenues and cash expenses are translated at the average rate of exchange during the month the transaction occurred. The resulting gains and losses are included in income. Foreign exchange gains or losses arising on translation of long-term liabilities are deferred and amortized over the remaining term of the liabilities.

Income Taxes

The Company follows the deferral method of tax allocation accounting under which full provision is made for income taxes based on accounting income. This provision differs from income taxes currently payable as certain items of income and expense are included in accounting income in periods different from those in which they are reported in taxable income.

Per Common Share Amounts

The loss per common share and funds generated from operations per common share have been calculated using the weighted average number of common shares outstanding. In computing the loss per common share, the net loss as shown on the consolidated statement of income has been adjusted to reflect the provision for redemption premium on the redeemable convertible preferred shares.

Fully diluted loss per common share is not disclosed when the effect is anti-dilutive.

3. PROPERTY, PLANT AND EQUIPMENT

	December 31					
	1991			1990		
(millions of dollars)	Cost	Accumulated Depletion, Depreciation and Amortization	Net	Cost	Accumulated Depletion, Depreciation and Amortization	Net
Oil and gas properties:						
Canada	**$ 1,391.2**	**$ 273.1**	**$ 1,118.1**	$ 1,383.2	$ 180.5	$ 1,202.7
International	**50.2**	**19.3**	**30.9**	40.8	11.9	28.9
Oil sands mining and related facilities and developed rights	**45.2**	**4.5**	**40.7**	43.5	2.7	40.8
Other	**22.9**	**9.1**	**13.8**	21.6	5.0	16.6
	$ 1,509.5	**$ 306.0**	**$ 1,203.5**	$ 1,489.1	$ 200.1	$ 1,289.0

Included in property, plant and equipment at December 31, 1991 are assets with a net book value of approximately $518.0 million (1990 – approximately $577.0 million) which were acquired with zero tax basis, resulting in non-deductible depletion, depreciation and other non-cash costs (Note 8).

A significant portion of the Company's Canadian producing and non-producing properties are held jointly with Amoco Canada Resources Ltd. ("Amoco"). Effective June 1, 1990, the Company entered into a Joint Operating and Services Agreement with Amoco which replaced the Umbrella Operating Agreement and the Joint Exploration agreement which had provided for the operation of joint lands operated by Amoco and third parties together with limited administrative services. Under the new agreement, the company manages its exploratory and development projects, subject to limited delegation to Amoco for minor expenditures and expenditures related to unitized properties.

The Company has interests in producing properties in Indonesia and non-producing interests in Indonesia, Algeria, Italy, Australia and New Zealand.

In 1991 the Company sold oil and gas properties and related facilities for total proceeds of $45.0 million (1990 – $48.5 million) which resulted in gains of $8.4 million before income taxes (1990 – losses of $6.8 million) and losses of $1.8 million after income taxes (1990 – losses of $3.2 million).

4. LONG-TERM DEBT

		December 31			
		1991		1990	
	Repayment Dates	Outstanding (millions of dollars)	Weighted Average Interest Rate (a)	Outstanding (millions of dollars)	Weighted Average Interest Rate (a)
Production loan facility					
Term bank loan (U.S. $200.7 million)	1995 to 1998	**$ 231.9**	**7.8%**	$ 232.8	9.6%
Revolving bank loan	1994 to 1997	**143.0**	**8.2%**	148.0	13.4%
12 ⅝% notes payable (b)	1994	**60.3**	**12.6%**	60.3	12.6%
8.5% convertible subordinated debentures	2000	**100.0**	**8.5%**	100.0	8.5%
9% convertible subordinated debentures (b)	1995	**8.5**	**9.0%**	8.5	9.0%
6.75% convertible subordinated debentures (b)	1997	**0.3**	**6.8%**	0.4	6.8%
		$ 544.0		$ 550.0	

(a) Weighted average interest rates are stated as at December 31, 1991 and 1990 respectively and include, where applicable, effective interest rates arising out of interest rate swap and interest rate cap agreements. Under these agreements, interest on U.S. $90.0 million of the principal outstanding under the production loan facility at December 31, 1991 has been fixed at an effective interest rate of 9.7% per annum for periods ending between February 26, 1992 and November 1, 1992. Under the interest rate cap agreements, interest on an aggregate amount of U.S. $40.0 million has been capped at an interest rate of 8.9% per annum. Interest on an additional U.S. $75.0 million has been capped at 8.9% for periods commencing between February 26 and November 2, 1992. The interest rate cap agreements mature between November 1, 1996 and November 2, 1997.

(b) In consideration for an undertaking of guarantee fees of 0.75% per annum on outstanding debt balances, payment of principal and interest is guaranteed by TransCanada PipeLines Limited.

Production Loan Facility

The production loan facility was provided by a syndicate of lenders on May 2, 1989. The facility matures December 31, 1998 and consists of a revolving portion and a term portion available in U.S. dollars. The production loan facility provides for different interest rate options, all of which are based on market rates in effect from time to time.

The amount of credit available under the term portion of the facility decreases in four annual amounts of $60.0 million commencing December 31, 1995.

The amount of credit available under the revolving loan at December 31, 1991 was $152.7 million and is reduced by $4.1 million in 1993, $45.0 million in 1994 to 1996 and $13.6 million in 1997. The availability of credit under this facility is also reduced by certain receipts, principally proceeds from the sale of properties. Based on the utilization of this facility, the first repayment related to the $143.0 million outstanding at December 31, 1991 will not be required until December 31, 1994.

The production loan facility is secured principally by way of general assignments of book debts and floating charge debentures over all the assets of the Company. The agreement governing the production loan facility contains, among other things, certain covenants regarding (i) restrictions on new borrowings by the Company, (ii) interest coverage and net worth tests, (iii) conditions on the sale of properties by the Company, including the requirement that proceeds of such sales reduce the credit available under the production loan facility, (iv) restrictions on the payment of common share dividends without the lenders' consent, and (v) the maintenance of lending values (determined by the lenders on the basis of engineering reports) of the Company's western Canadian oil and gas properties.

The Company has access to a demand operating facility which is subject to the same security as the production loan facility. The unused portion of this facility amounted to $26.8 million at December 31, 1991.

Convertible Subordinated Debentures

8.5% Convertible Subordinated Debentures – on November 22, 1990 the Company issued 100,000 units for an aggregate cash consideration of $97.1 million, after deduction of underwriting fees. The net proceeds of this issue were used to reduce the production loan facility. Each unit consists of $1,000 principal amount of 8.5% convertible subordinated debentures due December 1, 2000 and 100 common share purchase warrants.

Each $1,000 principal amount of the 8.5% convertible subordinated debentures is convertible into 357 common shares of the Company. The debentures are not redeemable on or prior to May 21, 1994. Thereafter, and on or prior to November 21, 1995, the debentures will not be redeemable unless the weighted average price at which the common shares of the Company have traded during 20 consecutive trading days ending not more than five trading days prior to the giving of notice of redemption is at least 125% of the conversion price. Thereafter, the debentures may be redeemed at any time at par plus accrued interest.

9% Convertible Subordinated Debentures – each $1,000 principal amount of the 9% convertible subordinated debentures, which were issued by a wholly owned subsidiary, Encor Energy Corporation Inc. ("Encor Energy"), is convertible into approximately 59.54 redeemable preference shares of Encor Energy up to maturity on June 30, 1995. The 9% convertible subordinated debentures are redeemable by Encor Energy at 103% to June 30, 1992, decreasing thereafter by 1% per annum to June 30, 1994 and at par plus accrued interest thereafter.

6.75% Convertible Subordinated Debentures – each $1,000 principal amount of Encor Energy 6.75% convertible subordinated debentures is convertible into 100 redeemable preference shares of Encor Energy at any time up to April 30, 1997. After April 30, 1992 the debentures are redeemable by Encor Energy at any time at par plus accrued interest.

Any redeemable preference shares of Encor Energy issued upon conversion of the 9% or 6.75% convertible subordinated debentures would, upon issue, be immediately redeemed for $9.375 per share.

Repayment

Based on the balance outstanding at December 31, 1991, future minimum annual repayments are as follows:

(millions of dollars)	
1992	$ –
1993	–
1994	99.7
1995	105.4
1996	105.0
1997	73.9
1998	60.0
1999	–
2000	100.0
	$ 544.0

5. DEFERRED REVENUE AND OTHER

	December 31	
(millions of dollars)	**1991**	1990
Deferred natural gas revenue	**$ 14.2**	$ 22.4
Deferred foreign exchange gain	**4.7**	5.0
Accumulated provision for future removal and site restoration costs	**5.0**	–
Deferred term interest (a)	**–**	4.1
Other	**0.2**	0.3
	24.1	31.8
Less: current portion	**0.1**	4.2
	$ 24.0	$ 27.6

(a) On January 1, 1986, TCPL Resources Ltd., a wholly owned subsidiary, entered into term interest agreements with a third party whereby $39.8 million was received in exchange for future payments from net revenues derived from certain of the Company's oil and gas properties. The expense from these arrangements, which terminated in 1991, is included in financial charges.

6. SHARE CAPITAL

Authorized

The share capital of the Company is comprised of an unlimited number of first preferred shares issuable in series, one 7% non-cumulative, retractable, redeemable, voting special preferred share and an unlimited number of common shares without nominal or par value.

Issued and Outstanding

	Redeemable Convertible Preferred Shares (a)		Common Shares	
	Number of Shares	Amount (millions of dollars)	Number of Shares	Amount (millions of dollars)
Outstanding December 31, 1989	29,850,000	$ 235.0	151,715,390	$ 473.0
Issued for cash pursuant to flow-through share agreement (b)			2,114,723	3.9
Issued for cash under employee savings plan			408,100	1.0
Issued for cash upon exercise of stock options			2,552	–
Provision for redemption premium		13.3		
Outstanding December 31, 1990	29,850,000	248.3	154,240,765	477.9
Issued for cash pursuant to flow-through share agreement (b)			528,681	1.0
Issued for cash under employee savings plan			767,860	0.8
Provision for redemption premium		14.1		
Outstanding December 31, 1991	**29,850,000**	**$ 262.4**	**155,537,306**	**$ 479.7**

(a) The redeemable convertible preferred shares, which rank in priority to the common shares, (i) are convertible during a stipulated period into 74,618,433 common shares of the company, (ii) do not entitle the holders thereof to any dividend from the date of issue until after April 30, 1994, following which such holders will be entitled to a $0.70 per share annual cumulative dividend accruing from May 1, 1994 payable quarterly, (iii) generally do not carry the right to vote except to entitle the holders thereof to elect two persons to the Company's Board of Directors, (iv) are subject to a mandatory redemption by the Company in equal annual installments over a 10 year period commencing in 1999 at a price of $10 per share plus any accrued and unpaid dividends, and (v) are redeemable in whole or in part by the Company after April 1994 at a price of $10 per share plus any accrued and unpaid dividends.

The redemption price of $10 per share for the 29,850,000 redeemable convertible preferred shares represents a premium of $72.0 million over the consideration for these shares. This premium is being provided for through annual charges to deficit, determined using the interest method, in the period May 2, 1989 to April 30, 1994.

(b) The Company issued 528,681 common shares (1990 – 2,114,723) under a flow-through share agreement in 1991 for a cash consideration of $1.4 million (1990 – $5.6 million). Of the proceeds received, $0.4 million (1990 – $1.7 million) has been credited to deferred income taxes in recognition of the loss of tax pools renounced to investors.

(c) The Company issued 10,000,000 common share purchase warrants on November 22, 1990 in conjunction with the issue of the 8.5% convertible subordinated debentures (Note 4). Each warrant entitled the holder to purchase one common share of the Company at a price of $2.65. The warrants expired, unexercised, on January 21, 1992.

Reserved

(a) Equity Incentive Plan

At December 31, 1991 the Company has 4,997,448 common shares reserved for issuance to key employees under an equity incentive plan. Also at December 31, 1991, options to acquire 3,077,370 common shares were outstanding. These options are exercisable at 20% per annum from the first anniversary date following the date of grant and expire no later than 2000.

	Number of Common Share Options		
	Exercise Price of $2.57 per share	Exercise Price of $2.59 per share	Exercise Price of $2.30 per share
Granted during 1989 and outstanding December 31, 1989	2,636,275	–	–
Granted during 1990	–	88,700	999,500
Exercised during 1990	(2,552)	–	–
Forfeited during 1990	(184,302)	(2,500)	(9,500)
Outstanding December 31, 1990	2,449,421	86,200	990,000
Granted during 1991	–	–	–
Forfeited during 1991	(311,351)	(18,400)	(118,500)
Outstanding December 31, 1991	**2,138,070**	**67,800**	**871,500**

(b) Employee Savings Plan

At December 31, 1991 a total of 5,792,204 (1990 – 1,560,064) common shares remained reserved for issuance under the employee savings plan.

(c) Conversion of Redeemable Convertible Preferred Shares

A total of 74,618,433 common shares have been reserved for conversion of the redeemable convertible preferred shares.

(d) 8.5% Convertible Subordinated Debentures and Share Purchase Warrants

A total of 35,700,000 common shares have been reserved to cover the conversion of the 8.5% convertible subordinated debentures issued on November 22, 1990 (Note 4). An additional 10,000,000 common shares were reserved to cover the exercise of share purchase warrants issued in conjunction with the debentures. The warrants expired, unexercised, on January 21, 1992.

7. FINANCIAL CHARGES

(millions of dollars)	Year Ended December 31 1991	1990
Interest on long-term debt	**$ 50.5**	$ 67.7
Short-term interest and other financial charges	**4.1**	6.8
	$ 54.6	$ 74.5

The Company has not capitalized any interest to date.

8. INCOME AND OTHER TAXES

The provision for income and other taxes is summarized as follows:

(millions of dollars)	Year Ended December 31 1991	1990
Current income taxes in foreign jurisdictions	**$ 6.3**	$ 3.9
Deferred income taxes (recovery)	**10.4**	(3.8)
Alberta royalty tax credit	**(1.6)**	(1.8)
Capital taxes	**2.4**	3.1
	$ 17.5	$ 1.4

The total tax provision differs from the amount computed by applying the basic Canadian federal income tax rate to loss before taxes. The reasons for these differences are as follows:

(millions of dollars)	Year Ended December 31 1991	1990
Loss before taxes	**$ (58.1)**	$ (56.6)
Federal statutory income tax rate	**38.84%**	38.84%
Expected income tax benefit	**$ (22.6)**	$ (22.0)
Non-deductible royalties and payments to governments, net of resource allowance	**9.7**	0.1
Non-deductible depletion, depreciation and other non-cash costs (Note 3)	**25.4**	31.3
Difference between the federal statutory tax rate and rates of provincial and foreign authorities	**2.5**	1.5
Non-taxable proceeds from sale of properties	**–**	(10.3)
Other	**1.7**	(0.5)
Alberta royalty tax credit	**(1.6)**	(1.8)
Capital taxes	**2.4**	3.1
	$ 17.5	$ 1.4

9. OPERATING ACTIVITIES

Funds Generated from Operations

(millions of dollars)	Year Ended December 31 1991	1990
Net loss	**$ (75.6)**	$ (58.0)
Exploration expenses	**15.0**	21.1
Depletion, depreciation and amortization	**96.7**	100.0
Amortization of undeveloped rights	**17.5**	18.6
Dry holes and abandonments	**11.4**	16.0
Amortization of deferred charges and credits	**(0.9)**	(0.5)
(Gain) loss on sale of properties	**(8.4)**	6.8
Deferred income taxes (recovery)	**10.4**	(3.8)
	$ 66.1	$ 100.2

Decrease (Increase) in Non-Cash Working Capital

(millions of dollars)	Year Ended December 31 1991	1990
Accounts receivable and prepaid expenses	**$ 28.5**	$ (20.8)
Inventories	**0.3**	(1.2)
Accounts payable and accrued liabilities	**4.3**	20.6
Income and other taxes payable	**(0.4)**	(3.6)
	$ 32.7	$ (5.0)

10. PENSION PLAN

The Company has a non-contributory defined contribution pension plan which covers all permanent employees with more than one year's service. Contributions to the plan for 1991 were approximately $1.4 million (1990 – $1.3 million), all of which have been expensed, and are based on each employee's length of service with the Company, including predecessor companies, and annual remuneration.

11. COMMITMENTS AND CONTINGENCIES

Lease Commitments

The Company leases its head office premises from a company which is controlled by the pension funds of affiliates of BCE Inc. BCE Inc. holds 19.1% of the common shares and all of the redeemable convertible preferred shares of the Company. Annual lease obligations, excluding operating costs relating to the office premises which amounted to $1.0 million for the year ended December 31, 1991, and other commitments in respect of equipment operating leases and reservation of gas processing capacity for the next five years are as follows:

(millions of dollars)	Total Commitments	Office Premises	Other Commitments
1992	$ 10.3	$ 2.4	$ 7.9
1993	10.5	2.6	7.9
1994	9.3	2.8	6.5
1995	8.8	3.1	5.7
1996	9.4	3.3	6.1

Hedging Contracts

The Company participates in certain financial arrangements which act as a hedge against price fluctuations in future crude oil production. In 1991, these arrangements consisted primarily of crude oil swap contracts involving the sale of 2.7 million barrels of 1991 Canadian crude oil and condensate production at an average price of U.S. $27.81 per barrel.

The Company has entered into crude oil swap contracts involving the sale of 1.5 million barrels of 1992 crude oil and condensate production at an average price of U.S. $21.92 per barrel. In respect of certain of these contracts, the Company has sold options which, if exercised, would result in an additional 0.8 million barrels being sold at U.S. $22.00 per barrel.

Contingencies

The Company is involved in litigation and claims associated with normal operations. Management is of the opinion that any resulting settlements would not materially affect the financial position of the Company.

12. SEGMENTED INFORMATION

The Company's operations comprise only oil and gas exploration, development and production activities and are in the following geographic segments:

	Year Ended December 31, 1991		
(millions of dollars)	Canada	International	Total
Revenues	**$ 244.4**	**$ 25.1**	**$ 269.5**
Loss from operations	**(7.5)**	**(6.5)**	**(14.0)**
Identifiable assets	**1,270.2**	**45.9**	**1,316.1**
Depletion, depreciation and amortization	**88.5**	**8.2**	**96.7**
Amortization of undeveloped rights	**17.5**	**–**	**17.5**
Expenditures on property, plant and equipment	**54.5**	**17.2**	**71.7**
Exploration expenses	**7.1**	**7.9**	**15.0**

	Year Ended December 31, 1990		
(millions of dollars)	Canada	International	Total
Revenues	$ 289.9	$ 23.7	$ 313.6
Income (loss) from operations	33.2	(11.6)	21.6
Identifiable assets	1,351.2	45.7	1,396.9
Depletion, depreciation and amortization	93.3	6.7	100.0
Amortization of undeveloped rights	18.6	–	18.6
Expenditures on property, plant and equipment	66.5	24.7	91.2
Exploration expenses	12.0	9.1	21.1

The Company's Canadian oil and gas production is sold primarily to Canadian marketing companies. Direct export sales are not significant.

13. SUBSEQUENT EVENT

On January 31, 1992, the Company concluded a purchase and sale arrangement ("rationalization") with Amoco and Maligne Resources Limited whereby, effective March 1, 1992, interests in jointly owned oil and gas properties in western Canada are to be exchanged, resulting in all companies owning a higher average interest in the properties to be held after completion of rationalization.

The arrangement will reduce the number of oil and gas properties held by the Company in western Canada prior to rationalization by about 40%, while maintaining overall value. No gain or loss will be recorded on the exchange.

HISTORICAL SUMMARY

FINANCIAL

(unaudited)

Selected Quarterly Financial Data

The following sets forth selected quarterly financial data for the four quarters of 1991 and 1990.

	Quarter Ended			
(millions of dollars except per share amounts)	Mar. 31	June 30	Sept. 30	Dec. 31
1991				
Revenues, net of royalties	**73.9**	**62.4**	**63.0**	**70.2**
Income (loss) from operations	**1.0**	**(3.9)**	**–**	**(11.1)**
Net loss	**(17.4)**	**(21.0)**	**(15.5)**	**(21.7)**
Net loss applicable to common shareholders	**(20.9)**	**(24.5)**	**(19.1)**	**(25.2)**
Per common share	**$ (0.14)**	**$ (0.15)**	**$ (0.13)**	**$ (0.16)**
1990				
Revenues, net of royalties	83.4	66.4	77.1	86.7
Income (loss) from operations	8.6	(3.7)	5.7	11.0
Net loss	(12.9)	(22.0)	(7.9)	(15.2)
Net loss applicable to common shareholders	(16.2)	(25.4)	(11.2)	(18.5)
Per common share	$ (0.11)	$ (0.16)	$ (0.08)	$ (0.12)

Price Range of Common Shares

The Company's common shares are listed on the Toronto and Montreal stock exchanges. The Toronto Stock Exchange is the principal market on which the Company's common shares are traded.

The following table sets forth the quarterly high and low sales prices of the Company's common shares on The Toronto Stock Exchange.

	Mar. 31	June 30	Sept. 30	Dec. 31
1991				
High	**$ 1.82**	**$ 1.45**	**$ 1.15**	**$ 0.85**
Low	**$ 1.32**	**$ 0.95**	**$ 0.70**	**$ 0.24**

Common Share Capital

	December 31, 1991	December 31, 1990
Issued and outstanding	**155,537,306**	154,240,765
Reserved for:		
Conversion of redeemable convertible preferred shares	**74,618,433**	74,618,433
Key employee equity incentive plan	**4,997,448**	4,997,448
Employee savings plan	**5,792,204**	1,560,064
Flow-through shares	–	528,682
8.5% convertible subordinated debentures	**35,700,000**	35,700,000
Warrants (expired January 21, 1992)	–	10,000,000
Shares held by BCE Inc.	**29,702,130**	29,702,130
Fully diluted number of common shares	**268,933,109**	278,084,819

FINANCIAL

(unaudited)

Summary of Financial Results

(millions of dollars except per share amounts)	**1991**	1990	1989 [1]	1988 [1]	1987 [2]
Revenues					
Oil and natural gas liquids	**228.5**	263.7	251.7	232.0	302.2
Natural gas	**81.8**	104.9	117.8	113.9	103.2
Other	**13.3**	13.6	16.2	19.1	20.4
Less royalties	**(54.1)**	(68.6)	(68.2)	(63.0)	(81.7)
Net Revenues	**269.5**	313.6	317.5	302.0	344.1
Expenses					
Production	**116.6**	113.1	117.4	121.0	
Exploration	**15.0**	21.1	17.3	22.3	
General and administrative	**26.3**	23.2	20.1	21.1	
Non-cash	**125.6**	134.6	168.3	203.6	
Financial charges	**54.6**	74.5	88.3	90.0	
(Gain) loss on sale of properties	**(8.4)**	6.8	(52.2)	–	
Interest and other income	**(2.1)**	(3.1)	(6.0)	(4.8)	
	327.6	370.2	353.2	453.2	
Loss before taxes	**58.1**	56.6	35.7	151.2	
Income and other taxes	**17.5**	1.4	0.3	(40.4)	
Net loss	**75.6**	58.0	36.0	110.8	
Provision for redemption premium on convertible preferred shares	**14.1**	13.3	12.8	12.8	
Net loss applicable to common shareholders	**89.7**	71.3	48.8	123.6	
Per common share	**$ 0.58**	$ 0.47	$ 0.32	$ 0.81	
Funds generated from operations before exploration expenses	**66.1**	100.2	87.8	78.5	
Per common share – basic	**$ 0.43**	$ 0.66	$ 0.58	$ 0.52	
– fully diluted	**$ 0.28**	$ 0.44	$ 0.38	$ 0.34	
Weighted average number of common shares (millions)	**155.0**	152.3	151.7	151.7	

Balance Sheet Summary

Working capital	**10.6**	5.6	11.4	(1.5)
Total assets	**1,316.1**	1,396.9	1,475.9	1,723.3
Long-term debt	**544.0**	550.0	581.5	720.1
Deferred revenue and other	**24.0**	27.6	46.1	48.3
Deferred income taxes	**131.3**	120.5	122.6	130.5
Shareholders' equity	**542.6**	616.4	669.5	765.4

[1] *For comparison purposes for the period January 1, 1988 to May 2, 1989, information has been prepared on a pro forma basis to give effect to the adoption of the successful efforts made of accounting and assumes an interest rate of 12.5 percent on long-term debt of $720.1 million and a provision for redemption premium on convertible preferred shares.*

[2] *Also for comparison purposes, 1987 reflects the combination of Encor Energy Corporation Inc., TCPL Resources Ltd. and Aberford Resources Ltd. Certain information for this period is not available on a comparative basis and therefore has not been included in this table.*

OPERATIONS

(unaudited)

Oil and Natural Gas Liquids Production

(Bbls/day)	**1991**	1990	1989[1]	1988[1]	1987[1]
Western Canada					
Conventional oil	**20,019**	23,305	26,728	29,476	29,121
Synthetic oil	**2,064**	1,942	1,858	1,880	1,701
Natural gas liquids	**5,006**	4,842	6,344	6,916	6,422
	27,089	30,089	34,930	38,272	37,244
International					
Indonesia	**6,045**	4,282	4,958	3,720	3,476
Australia	**9**	148	198	177	223
	6,054	4,430	5,156	3,897	3,699
Total	**33,143**	34,519	40,086	42,169	40,943

Natural Gas Sales

(Mmcf/day)					
Western Canada	**166**	182	210	203	175

Drilling Activity

Western Canada

Exploration Wells	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Oil	**–**	**–**	3	1.5	5	1.6	33	10.1	51	16.3
Gas	**3**	**0.5**	15	5.5	3	1.3	25	8.2	21	6.4
Dry	**3**	**0.6**	18	8.5	15	6.2	61	18.1	61	19.1
Total	**6**	**1.1**	36	15.5	23	9.1	119	36.4	133	41.8
Development Wells										
Oil	**142**	**6.3**	173	15.2	144	14.2	338	47.6	390	60.4
Gas	**57**	**6.3**	101	10.9	70	3.8	92	8.5	44	4.7
Dry	**15**	**2.0**	22	1.7	25	3.9	49	7.7	41	9.6
Total	**214**	**14.6**	296	27.8	239	21.9	479	63.8	475	74.7

International

Exploration Wells	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Oil	**2**	**0.3**	4	0.5	9	0.2	15	1.0	13	1.1
Gas	**1**	**0.1**	1	0.4	3	0.7	1	0.1	1	0.1
Dry	**20**	**1.7**	16	1.9	16	0.7	20	2.4	7	0.6
Total	**23**	**2.1**	21	2.8	28	1.6	36	3.5	21	1.8
Development Wells										
Oil	**22**	**0.4**	68	1.5	22	0.7	8	0.3	4	0.2
Gas	**–**	**–**	–	–	–	–	–	–	–	–
Dry	**2**	**0.1**	3	0.1	–	–	–	–	–	–
Total	**24**	**0.5**	71	1.6	22	0.7	8	0.3	4	0.2

[1] *For comparison purposes, the periods 1987 through May 2, 1989, reflect the combination of Encor Energy Corporation Inc., TCPL Resources Ltd. and Aberford Resources Ltd.*

DIRECTORS AND OFFICERS

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Chairman, President and Chief Executive Officer
of TransCanada PipeLines Limited

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Rancho Santa Fe, California
Natural Resources Consultant

J. V. Raymond Cyr, O.C.
Montreal, Quebec
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North York, Ontario
Corporate Director/Consultant

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Calgary, Alberta
President and Chief Executive Officer of Encor Inc.

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Dollard-des-Ormeaux, Quebec
Senior Vice-President, Law & Corporate Services of BCE Inc.

Dennis G. Hart, Q.C.
Calgary, Alberta
Senior Partner of Macleod Dixon

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Jackson's Point, Ontario
Corporate Director

William J. Whelan
Calgary, Alberta
Financial Consultant

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President and Chief Executive Officer

Randall J. Findlay
Senior Vice-President, Production & Engineering

Stephen J. Letwin
Vice-President, Finance and Chief Financial Officer

Raymond G. Sawka
Senior Vice-President, International

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Vice-President, Human Resources & Administration

E. Susan Evans
Vice-President, Law & Corporate Affairs
and Corporate Secretary

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Vice-President, Engineering

John H. Jubenvill
Vice-President, Exploration (North America)

Sandro S. Silenzi
Vice-President, Exploration (International)

Elliott R. Bingham
Treasurer

Harry M. Eisenhauer
Assistant Corporate Secretary

Ardith D. Wagner
Assistant Corporate Secretary

CORPORATE INFORMATION

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Shaunavon, Saskatchewan
Drayton Valley, Alberta
Grande Prairie, Alberta
Red Deer, Alberta

Regional Offices
Jakarta, Indonesia

Auditors
Peat Marwick Thorne, Calgary

Counsel
Macleod Dixon, Calgary

Bankers
Bank of Montreal
Canadian Imperial Bank of Commerce

Registrars and Transfer Agents
For Common Shares and 8.5% Convertible Subordinated Debentures issued by Encor Inc.:
Montreal Trust Company of Canada
Corporate Services Division
411 - 8th Avenue S.W., Calgary, Alberta, T2P 1E7
And principal offices in Vancouver, Regina, Winnipeg, Toronto, Montreal and Halifax

For 6.75% Convertible Subordinated Debentures:
The Royal Trust Company
333 - 7th Avenue S.W., Calgary, Alberta, T2P 2Z1
And its principal offices in Vancouver, Regina, Winnipeg, Toronto and Montreal

For 9% Convertible Subordinated Debentures:
First City Trust Company
500 - 5th Avenue S.W., Calgary, Alberta, T2P 0L9
And principal offices in Vancouver, Regina, Winnipeg, Toronto, Montreal and Hamilton

For 12 ⅝% TCPL Resources Ltd. Notes:
Fiscal and Paying Agent
The Royal Bank of Canada Europe Limited
71 Queen Victoria Street, London, U.K., EC4V 4DE
And principal offices in Toronto, Paris, Geneva, Brussels and Luxembourg

Investor Information
(403) 231-1888

The Annual Information Form for the year ended December 31, 1991 is available upon request.

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